PB-239 315

ECONOMIC ANALYSIS OF EFFLUENT GUIDELINES STEAM ELECTRIC POWERPLANTS

TEMPLE, BARKER AND SLOANE, INCORPORATED

PREPARED FOR
ENVIRONMENTAL PROTECTION AGENCY

DECEMBER 1974

DISTRIBUTED BY:
NTIS
National Technical Information Service
U. S. DEPARTMENT OF COMMERCE

TECHNICAL REPORT DATA PAGE	1. Report No. EPA230/2-74-006	2.	PB 239 315

4. Title and Subtitle Economic Analysis of Effluent Guidelines Steam Electric Powerplants	5. Report Date December 1974
	6.
7. Author(s) Howard W. Pifer Michael L. Tennican et. al	8. Performing Organization Rept. No.
9. Performing Organization Name and Address Temple, Barker & Sloane, Inc. 15 Walnut Street Wellesley Hills, Massachusetts 02181	10. Project/Task/Work Unit No.
	11. Contract/Grant No. 68-01-2803
12. Sponsoring Organization Name and Address Office of Planning and Evaluation Environmental Protection Agency Washington, D.C. 20460	13. Type of Report & Period Covered Final
	14.

15. Supplementary Notes

16. Abstracts

An initial analysis of the economic impact of the proposed water effluent guidelines upon the Steam Electric Power Industry was performed, based upon planning assumptions being used by the Technical Advisory Committee on Finance for the National Power Survey. The most likely impact in terms of capital expenditures will be $4.0 billion through the next decade. Of this $2.7 billion will be required to meet the thermal and $1.3 billion to meet the chemical regulations, an increase of 1.9% through 1977 and 2.4% from 1978 to 1983. Annual operating costs should increase 1% during the next decade. The increase to the consumer will be less than 2%.

17. Key Words and Document Analysis. 17a. Descriptors

Economic Analysis
Effluent Guidelines
Steam Electric Powerplants
Electric Utility Industry
Policy-Testing model (PTm)

17b. Identifiers/Open-Ended Terms

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
US Department of Commerce
Springfield, VA. 22151

PRICES SUBJECT TO CHANGE

17c. COSATI Field/Group

18. Availability Statement	19. Security Class (This Report) UNCLASSIFIED	21. No. of Pages
	20. Security Class (This Page) UNCLASSIFIED	

ECONOMIC ANALYSIS
OF EFFLUENT GUIDELINES
STEAM ELECTRIC POWERPLANTS

HOWARD W. PIFER
T. JAMES GLAUTHIER

JAMES M. SPEYER

MICHAEL L. TENNICAN
JOHN W. WEBER

MICHELE ZARUBICA

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Planning and Evaluation
Washington, D. C. 20460

December 1974

PREFACE

The attached document is a contractor's study prepared with the supervision and review of the Office of Planning and Evaluation of the U.S. Environmental Protection Agency (EPA). Its purpose is to provide a basis for evaluating the potential economic impact of effluent limitations and guidelines and standards of performance established by EPA pursuant to sections 301, 304(b) and 306 of the Federal Water Pollution Control Act.

This study supplements the EPA technical "Development Document" issued in conjunction with the promulgation of guidelines and standards for point sources within this industry category. The Development Document surveys existing control methods and technologies within this category and presents the investment and operating costs associated with various control technologies. This study supplements that analysis by estimating the broader economic effects (including increases in capital requirements, price increases, continued viability of affected plants, employment, industry growth and foreign trade) of the required application of certain of these technologies.

This study has been submitted in fulfillment of contract No. 68-01-2803 by Temple, Barker & Sloane, Inc. Work was completed as of December 1974. The study is an update of an earlier study prepared with the assistance of Temple, Barker & Sloane, Inc. entitled "Economic Analysis of Proposed Effluent Guidelines: Steam Electric Powerplants." The earlier report was circulated in conjunction with the publication in the Federal Register of a notice of proposed rulemaking for the subject point source category. The analysis contained in the original study has been updated based upon information received during the period of time between publication of the notice of proposed rulemaking and the promulgation of the final regulation.

This report represents the conclusions of the contractor. It has been reviewed by the Office of Planning and Evaluation and approved for publication. Approval does not signify that the contents necessarily reflect the views of the Environmental Protection Agency. The study has been considered, together with the Development Document, information received in the form of public comments on the proposed regulation, and other materials in the establishment of final effluent limitations guidelines and standards of performance.

ACKNOWLEDGMENTS

The authors of this study would like to take this opportunity to thank the many individuals who contributed to this study, especially Walter Barber and Victor Kimm of the Environmental Protection Agency (Office of Planning and Evaluation); Robert Uhler of the Federal Power Commission (Office of Economics.); Valerie Bennett, Robert Elgin and Richard Rosen of Energy Resources Company, Inc.; Angela Lancaster and Lewis Perl of National Economic Research Associates, Inc.; and Lee Gladden and Elinor Scholl of the TBS professional staff.

In addition, a special thanks to the following members of the TBS staff who assisted in the preparation of the final report: Cynthia Kornuta and Pamela Scricco of the Energy and Environment Group and Arlene Ficcaglia, Judy Weitzman, Ann Eberhardt, Debby Homer and Lee O'Neil of the Editing and Production staff.

Responsibility for any errors or omissions remains with the authors.

TABLE OF CONTENTS

PREFACE i
ACKNOWLEDGMENTS iii
LIST OF EXHIBITS AND APPENDICES viii
EXECUTIVE SUMMARY 1

TEXT

I. THE CHANGING NATURE OF THE ELECTRIC UTILITY INDUSTRY (1960-1973)

Introduction 7

Industry Structure 8

The Secure Years (1960-1966) 12

The Turning Point (1966-1969) 20

The Dilemma Years (1969-Present) 24

Summary 36

II. BASELINE ELECTRIC UTILITY INDUSTRY PROJECTIONS (1974-1990)

Introduction 39

Industry Structure 42

Generating Capacity 44

Capital Cost Factors 48

Operating Cost Factors 50
Financial Policy Parameters 51
Economic and Financial Implications . . . 56
Summary of Baseline Conditions 59
Historic Growth Assumptions 61

III. ANALYSIS OF THE FINAL EFFLUENT GUIDELINES

Introduction 67
Structure of Assumptions 69
Thermal Capital and Operating Cost Factors 70
Thermal Capacity Coverage Estimates . . . 74
Thermal Installation Schedules 84
Impact of Thermal Guidelines 85
Chemical Capital and Operating Cost Factors 99
Chemical Capacity Coverage Estimates 100
Chemical Installation Schedules 101
Impact of Chemical Guidelines 102
Total Impact of Final Guidelines 105

IV. EVALUATION OF OTHER THERMAL OPTIONS

Introduction 115

Thermal Capacity Coverage Estimates . . . 117

Impact of Thermal Options 117

Summary 122

V. EVALUATION OF STATE WATER QUALITY STANDARDS

Introduction 123

Thermal Capacity Coverage Estimates . . . 123

Impact of State Water Quality Standards. . 125

VI. ENVIRONMENTAL IMPACT OF THERMAL GUIDELINES

Introduction 129

Technology of Thermal Pollution. 129

Factors that Influence Environmental Impact 136

Environmental Evaluation of the Guideline Options 149

VII. ALTERNATIVE ASSUMPTIONS SUBMITTED BY UWAG

Introduction 157

Areas of Difference in Assumptions 159

Alternative Thermal Cost Factors 162

Impact of Cost Factors (Thermal) 167

Alternative Chemical Cost Factors 169

Impact of Cost Factors (Chemical) 172

Alternative Baseline Conditions 173

Impact of Growth Assumptions (Thermal) . . . 176

Impact of Interaction Effect (Thermal) . . . 178

Impact of Growth Assumptions (Chemical). . . 180

Impact of Interaction Effect (Chemical). . . 181

Summary 182

EXHIBITS

APPENDIX A PTM RESEARCH METHODOLOGY

APPENDIX B PTM SUMMARY STATISTICS

LIST OF EXHIBITS AND APPENDICES

I. THE CHANGING NATURE OF THE ELECTRIC UTILITY INDUSTRY (1960 - 1973)

	EXHIBIT	PAGE
Growth in Energy Demand and in Peak Load Relatively Predictable Through Early 1960s	1	185
Annual Load Factor Remarkably Constant Through Early 1960s	2	186
Cost Per Kilowatt of Installed Capacity at End of 1960s Was About Same Level as at Start	3	187
Investment in Electric Plant Per Dollar of Revenue Quite Constant During Early 1960's	4	188
Capital Expenditures Grew Very Slowly in Early 1960s	5	189
Cost Per Kilowatt-Hour--Both Total and Major Components--Declined During Early 1960s	6	190
Growth in Revenues Steady and Consistent Through Early 1960s	7	191
Rates Declined Along With Revenues Per KWH Through the Early 1960s	8	192
Number of Customers and Average Usage Per Customer Increased Significantly During the Early 1960s	9	193
Financial Results Good Through the Early 1960s	10	194
Indicators of Investment Climate Improved Significantly During Early 1960s	11	195

	EXHIBIT	PAGE
Utility Management Shifted Their Capitalization Toward Equity During the Early 1960s	12	196
Internally Generated Funds Became More Important During the Early 1960s as Both New Debt and Equity Tapered Off	13	197
Industrial Bond Rate Virtually Constant Until 1965, Then Moved Sharply Upward	14	198
Requirements for External Financing Has Grown Dramatically Since Mid-1960s	15	199
Growth in Energy Consumption and in Peak Load Accelerated Since the Early 1960s and Predictability Deteriorated	16	200
Cost Per KW of Installed Capacity Increased Dramatically Since the 1960s	17	201
Capital Expenditures--After a Period of Relative Constancy in Early 1960s--Have Grown Rapidly Since That Time	18	202
Internally Generated Funds Not Growing as Fast as Need for Funds Since 1965	19	203
Cost Per Kilowatt-Hour--Both Total and Major Components--Bottomed Out in Late 1960s, Then Climbed Steadily	20	204
Fuel Cost Components Bottomed Out in Mid- to Late-1960s and Increased Since	21	205
Net Income from Electric Operations Up Substantially Since Mid-1960s	22	206
Allowance for Funds During Construction Becoming an Increasingly Larger Portion of Total Net Income	23	207

	EXHIBIT	PAGE
Capital Structures Relatively Unchanged Over the Years	24	208
Rate of Growth of Common Equity Up Substantially in Recent Years; Common Stock Growth Up Even More	25	209
Return on Common Equity Deteriorated in Recent Years	26	210
Price Earnings Ratio of Common Stock Deteriorated Badly in Recent Years	27	211
Ratio of Market Price to Book Value of Common Stock Deteriorated Steadily and is Now Less Than One	28	212
Growth Rate in Earnings Per Share Deteriorated Sharply Since the Early 1960s	29	213

II. BASELINE ELECTRIC UTILITY INDUSTRY PROJECTIONS (1974-1990)

	EXHIBIT	PAGE
Factors Influencing the Electric Utility Industry's Rate of Growth in Generation Capacity and Electric Energy Under Moderate Growth Assumptions, 1973 to 1990	30	214
Total Electric Utility Industry Generation Capacity Additions, Retirements, and Totals by Plant Type and Total Sales to Ultimate Consumers Under Moderate Growth Assumptions, 1973 to 1990	31	216
Generating Capacity Cost Growth	32	217
Schedule of Construction Work in Progress Cash Payments	33	218
Operations and Maintenance Cost Growth	34	219
Economic and Financial Projections of Baseline Conditions With Moderate Growth Assumptions, For Selected Years	35	220
Factors Influencing the Electric Utility Industry's Rate of Growth in Generation Capacity and Electric Energy Under Historic Growth Assumptions, 1973 to 1990	36	221
Total Electric Utility Industry Generation Capacity Additions, Retirements, and Totals by Plant Type and Total Sales to Ultimate Consumers Under Historic Growth Assumptions, 1973 to 1990	37	222

	EXHIBIT	PAGE
Economic and Financial Projections of Baseline Conditions with Historic Growth, for Selected Years	38	223
Economic and Financial Impact of Reduced Growth - 1977	39	224
Economic and Financial Impact of Reduced Growth - 1983	40	225
Economic and Financial Impact of Reduced Growth - 1990	41	226

III. ANALYSIS OF THE FINAL EFFLUENT GUIDELINES

	EXHIBIT	PAGE
Capital Cost Growth--Thermal Guidelines	42	227
Annual Operating Cost Growth--Thermal Guidelines	43	228
Non-Nuclear Capacity Coverage by In Service Year	44	229
Nuclear Capacity Coverage by In Service Year	45	230
Installation Schedule for Retrofitted Units	46	231
Economic and Financial Projections With Thermal Pollution Control Equipment for Economic Reasons, for Selected Years	47	232
Economic and Financial Projections of Final Thermal Guidelines Before Section 316(a) Exemptions, for Selected Years	48	233
Economic and Financial Projections of Final Thermal Guidelines After Section 316(a) Exemptions, for Selected Years	49	234
Economic and Financial Impact of Thermal Pollution Control Equipment for Economic Reasons--1977	50	235
Economic and Financial Impact of Thermal Pollution Control Equipment for Economic Reasons--1983	51	236
Economic and Financial Impact of Thermal Pollution Control Equipment for Economic Reasons--1990	52	237

	EXHIBIT	PAGE
Economic and Financial Impact of Final Thermal Guidelines Before Section 316(a) Exemptions--1977	53	238
Economic and Financial Impact of Final Thermal Guidelines Before Section 316(a) Exemptions--1983	54	239
Economic and Financial Impact of Final Thermal Guidelines Before Section 316(a) Exemptions--1990	55	240
Economic and Financial Impact of Final Thermal Guidelines After Section 316(a) Exemptions--1977	56	241
Economic and Financial Impact of Final Thermal Guidelines After Section 316(a) Exemptions--1983	57	242
Economic and Financial Impact of Final Thermal Guidelines After Section 316(a) Exemptions--1990	58	243
Capital Cost Growth--1977 Chemical Guidelines	59	244
Capital Cost Growth--1983 Chemical Guidelines	60	245
Annual Operating Cost Growth--1977 Chemical Guidelines	61	246
Annual Operating Cost Growth--1983 Chemical Guidelines	62	247
Economic and Financial Projections of Final Chemical Guidelines, For Selected Years	63	248
Economic and Financial Impact of Final Chemical Guidelines--1977	64	249

	EXHIBIT	PAGE
Economic and Financial Impact of Final Chemical Guidelines--1983	65	250
Economic and Financial Impact of Final Chemical Guidelines--1990	66	251
Economic and Financial Impact of Final Regulations--1977	67	252
Economic and Financial Impact of Final Regulations--1983	68	253
Economic and Financial Impact of Final Regulations--1990	69	254

IV. EVALUATION OF OTHER THERMAL OPTIONS	EXHIBIT	PAGE
Non-Nuclear Coverage for Existing Units	70	255
Nuclear Coverage for Existing Units	71	256
Economic and Financial Projections of Option 1 (1979) After Section 316(a) Exemptions, for Selected Years	72	257
Economic and Financial Projections of Option 2 (1974) After Section 316(a) Exemptions, for Selected Years	73	258
Economic and Financial Projections of Option 3 (1972) After Section 316(a) Exemptions, for Selected Years	74	259
Economic and Financial Projections of Option 4 (1961, $<$ 200 MW) After Section 316(a) Exemptions, for Selected Years	75	260
Economic and Financial Projections of Option 5 (1956, $<$ 25 MW, $<$ 40%) After Section 316(a) Exemptions, for Selected Years	76	261
Economic and Financial Projections of Proposed Guidelines (March 1974) After Section 316(a) Exemptions, for Selected Years	77	262

V. EVALUATION OF STATE WATER QUALITY STANDARDS

	EXHIBIT	PAGE
Non-Nuclear Coverage for Existing Units	78	263
Nuclear Coverage for Existing Units	79	264
Economic and Financial Projections of Final Thermal Guidelines After Section 316(a) Exemptions, and After State Water Quality Standards, for Selected Years	80	265
Economic and Financial Impact of State Water Quality Standards--1977	81	266
Economic and Financial Impact of State Water Quality Standards--1983	82	267
Economic and Financial Impact of State Water Quality Standards--1990	83	268

VI. ENVIRONMENTAL IMPACT OF THE THERMAL GUIDELINES

	EXHIBIT	PAGE
Annual Mix of Receiving Water Types--Open Cycle Steam Electric Capacity	84	269
Annual Mix of Cooling Method--Steam Electric Capacity	85	270
Safezone on Rivers Used for Once Through Cooling	86	271
Mix of Capacity by Unit Size	87	272
Distribution of Projected 1978 Units by Year Placed in Service	88	273
Comparison of Capacity Projections Used for Environmental Versus Economic Analysis	89	274
Age Composition and Risk Characteristics of Capacity In-Service by 1983	90	275
Environmental Risk, Variations on 1970-73 Size Criterion With 1970 Exemption	91	276
Environmental Risk, Alternative Age Criteria	92	277

VII. ALTERNATIVE ASSUMPTIONS SUBMITTED BY UWAG

	EXHIBIT	PAGE
A Summary of Alternative Economic and Financial Projections of Final Thermal Guidelines for the Period 1974-1983	93	278
A Summary of Alternative Economic and Financial Projections of Baseline Chemical Guidelines for the Period 1974-1983	94	279
A Summary of Alternative Economic and Financial Projections of Baseline Conditions for the Period 1974-1983	95	280
A Summary of Alternative Economic and Financial Projections of Final Thermal Guidelines for the Period 1974-1983	96	281
A Summary of Alternative Economic and Financial Projections of Final Thermal Guidelines for the Period 1974-1983	97	282
A Summary of Alternative Economic and Financial Projections of Final Chemical Guidelines for the Period 1974-1983	98	283

APPENDICES

A. PTM RESEARCH METHODOLOGY

	FIGURE	PAGE
Interactions Between the Environment and the Physical and Financial Characteristics of the Electric Utility Industry	A-1	296
Determinants of Plant and Equipment in Service and in Construction for the Electric Utility Industry	A-2	297
Determinants of Uses of Funds for the Electric Utility Industry	A-3	298
Determinants and Composition of Total Sources of Funds for the Electric Utility Industry	A-4	299
Determinants of Revenues, Expenses, and Profits for the Electric Utility Industry	A-5	300

B. PTM SUMMARY STATISTICS

	FIGURE	PAGE
Economic and Financial Projections of Baseline Conditions, for Selected Years	B-1	308
Investor-Owned Electric Utilities Combined Income Statement, Baseline Conditions - 1983	B-2	309
Investor-Owned Electric Utilities Combined Balance Sheet, Baseline Conditions - 1983	B-3	310
Investor-Owned Electric Utilities Combined Applications and Sources of Funds, Baseline Conditions - 1983	B-4	311
Investor-Owned Electric Utilities Combined Reconciliation of Taxes, Baseline Conditions - 1983	B-5	312

EXECUTIVE SUMMARY

On 4 March 1974 the Environmental Protection Agency (EPA) published a notice of proposed rulemaking announcing its intention to establish limitations on the discharge of pollutants into waterways by existing and new point sources within the electric utility industry. These proposed regulations were promulgated pursuant to the relevant sections of the Federal Water Pollution Control Act of 1972 (Act) as amended. With respect to thermal pollution, the proposed rulemaking exempted all small units (defined by the Federal Power Commission as units in plants of 25 megawatts or less and in systems of 150 megawatts or less in total capacity), and all units which were scheduled for retirement prior to 1990.

Interested parties were invited to submit written comments on the proposed regulations, and EPA convened public hearings in July to afford those who had submitted comments to explain the substance of their position in detail. Based upon these written comments, public hearings, and subsequent interaction among interested parties, the guidelines were revised.

On 8 October 1974, EPA published in the *Federal Register (39 FR 36186)* final guidelines and standards for steam electric power generation. The final thermal guidelines exempt all units placed into service before 1970, and all but the largest baseload units (defined as units of 500 megawatts or greater) placed into service between 1 January 1970 and 1 January 1974. Thus, the final thermal guidelines differed from those proposed in March 1974 in terms of the proportion of existing steam electric units which were covered by the Act. In addition, the final chemical guidelines were modified from those previously proposed.

EPA contracted with Temple, Barker and Sloane, Inc. (TBS) to evaluate the overall economic impact of these guidelines.[1]

---

[1] *Throughout this report, the economic and financial implications will be attributed to both the Act and the guidelines. Technically, they represent the impact of the final guidelines, not the Act itself.*

The purpose of this document is to describe in some detail the analyses performed and conclusions reached during the evaluation of the economic and financial implications of the final guidelines. It is divided into two major parts. The first is an executive summary which provides an overview of the study and its findings. The second part is the full report which details the economic impact of the final guidelines, evaluates alternative options which were considered (including the original proposal) and summarizes the assessment of environmental risk performed by Energy Resources Company, Inc.

BASELINE CONDITIONS

Prior to the Arab oil embargo, the electric utility industry was planning to spend more than $205 billion in constant 1974 dollars for capital equipment placed in service during the 1974-83 decade before any consideration of EPA effluent guidelines. Based upon the planning assumptions currently being used by the Technical Advisory Committee on Finance for the National Power Survey, the most likely level of capital expenditures prior to the effluent guidelines would be less than $180 billion (1974 dollars). This decline of approximately $25 billion in capital expenditures reflects the decline in the rate of growth by less than 1 percent to the current projections of 5.5 percent over the next decade. In order to provide perspective, EPA has utilized these most recent industry projections as a baseline from which to summarize relative changes in economic impact associated with the effluent guidelines.

ECONOMIC IMPACT OF FINAL GUIDELINES

Based upon the revised guidelines, EPA estimates that the most likely economic impact in terms of capital expenditures will be $4.0 billion in constant 1974 dollars over the next decade. Of this total, $2.7 billion will be required to meet the thermal and $1.3 billion to meet the chemical regulations.

The following brief table summarizes the timing of these capital expenditures:

CAPITAL EXPENDITURES
(Billions of 1974 Dollars)

	1974-77	1978-83	1984-90
Baseline Conditions	$53.4	$125.6	$219.8
+Thermal	$ 0.3	$ 2.4	$ 1.8
+Chemical	0.7	0.6	0.5
Total Impact	$ 1.0	$ 3.0	$ 2.3
Percent of Baseline	1.9%	2.4%	1.0%

In the short run, the final guidelines would increase the capital requirements of the industry by less than 2 percent. The impact through the early 1980s increases to 2.4 percent as a result of conversion to closed-cycle cooling required by the thermal guidelines. Finally, the long-run impact is estimated to be approximately 1 percent.

In addition to increasing capital expenditures, the regulations will cause an increase in operations and maintenance expenses. This increase in expenses results from the costs associated with operating closed-cycle cooling systems and chemical cleanup systems, from costs required to operate additional capacity needed to offset the reduction in generating efficiency, and from the costs attendant with generation capability lost during the installation period. These annual operations and maintenance expenses are expected to increase by 1.0 percent during the next decade.

The ultimate economic impact of the guidelines is reflected in the average cost of electricity to the consumer. Increased capital and operating expenditures are expected to increase the cost of electricity by 0.4 mills per kilowatt-hour by 1983. This represents less than a 2 percent increase in the future cost of electricity.

IMPACT UPON ENERGY DEMAND AND BALANCE OF TRADE

Compliance with the final guidelines will both increase fuel consumption within the industry and increase the trade deficit resulting from the importation of petroleum products. The impact of the regulations will increase the demand for coal by less than 1.0 percent and for oil by approximately 0.1 percent by 1983. The added demand for petroleum products under the most adverse conditions will amount to approximately 18,000 barrels per day which would increase the trade deficit by a maximum of $80 million in constant 1974 dollars.

ASSESSMENT OF ENVIRONMENTAL RISK

EPA commissioned a separate environmental survey that concluded that 18 percent of the total generation capacity operating in 1983 would be potentially of high risk, where high risk was defined as a plant whose effluent discharge was of potential danger to fish or wildlife in nearby waterways.

Compliance with the regulations requires almost half of these high risk plants be converted to closed-cycle cooling systems. By 1983, therefore, only 10 percent of the nation's generation capacity will be considered high risk, and while these remaining high risk plants will be exempted from compliance with the guidelines, all may be covered by water quality standards established by the various states.

CONCLUDING COMMENT

Compliance with the water pollution regulations - while amounting to a large number of dollars - is small when compared with the total needs of the industry. The relative impact ranges from 1 to 2 percent depending upon the particular economic measure.

In addition, the magnitude of the economic impact pales when compared to the reduction in resources projected to be needed by the industry in the next decade. To illustrate, capital expenditures attributable to the final guidelines are expected to total $4.0 billion during the next decade; yet the recent decline in industry growth will reduce the capital expenditures originally projected by more than $25 billion. If the electric utility industry could have met the capital requirements projected prior to last winter, they should experience little trouble meeting the added requirements to comply with the final guidelines.

This is not to say that the industry is without problems - in fact, it is currently in dire financial straits (see Chapter I). But the plight of the electric utility industry is not intimately tied to the environmental movement. Rather, the problems of the industry evolve from other conditions within the industry. The decision of EPA to delay the major expenditures until the 1980s should ease the short-term capital crunch and provide an adequate period for the underlying problems to be corrected.

GUIDE TO THE REPORT

The full report consists of seven chapters and attendant exhibits and appendices.

- Chapter I surveys the environment of the electric utility industry since 1960 and traces the events which have led up to its current economic and financial problems.
- Chapter II details the baseline operating conditions projected through 1990 without regard for the requirements associated with meeting environmental standards.
- Chapter III provides an evaluation of the economic impact resulting from the final guidelines, both thermal and chemical.
- Chapter IV outlines the economic analysis of a set of alternatives representative of the many options which were evaluated prior to the selection of the final guidelines - including the guidelines proposed in March 1974.

- Chapter V details the potential impact that the water quality standards set by the individual states could have on those existing generating units not covered by the final guidelines.

- Chapter VI summarizes the environmental risk associated with the final guidelines and with some of the other options considered.

- Chapter VII compares the economic impact that results from using the underlying assumptions submitted by the Utility Water Act Group.

The appendices provide an overview of the research methodology employed.

I. THE CHANGING NATURE OF THE ELECTRIC UTILITY INDUSTRY

(1960 - 1973)

INTRODUCTION

The importance of electrical energy can hardly be overstated. The use of energy in all its forms in the United States has been growing at a compound annual rate of 4.4 percent since 1960. During the same period, however, the use of electrical energy has been growing at 7.3 percent and now consumes in the generating process 23 percent of all forms of energy used in the country - up from 16 percent in 1960.

The industry that produces this energy - the electric utility industry - truly has been one of the great growth industries in the American economy, enjoying favorable trends in almost every factor affecting its growth and profitability. Some time in the latter half of the 1960s, however, significant changes began to occur in the industry when a multiplicity of events took place within a relatively short span of years. These large changes were not the usual downturn in demand or influx of competition that have signalled a turn-about in many other growth industries. Demand continued to grow steadily - even accelerate - while the competitive situation did not change from the regulated monopoly status long enjoyed by companies within the industry. A much different type of change began to affect the industry, and as a result, a dramatic uncertainty began to envelop the electric utility industry.

This uncertainty made itself felt across a range of factors - from load projections to costs for new capacity and fuel to financing capabilities. The list could go on and on, each factor contributing its weight to the problem of generating a fair return and financing growth in a way equitable to investors and consumers alike. The day of predictability and relatively secure decision-making ended; in its place came days of uncertainty and genuine concern over the most appropriate way to meet the demands and challenges now facing the industry.

INDUSTRY STRUCTURE

The electric utility industry is composed of three basic kinds of companies - investor-owned, publicly owned, and co-operatives. The publicly owned utilities could be further categorized into those owned by state and local governments and those owned by the federal government. There are slightly in excess of 3500 separate electrical systems in the United States, almost two-thirds of which are publicly owned. Over 73 percent of the publicly owned and co-operative systems in the country are engaged in distribution only. By contrast, most of the approximately 500 investor-owned electric utilities are engaged in generation, transmission, and distribution.

The types of firms in the electric utility industry differ considerably in generating capacity and in production of electrical energy. Investor-owned utilities - the smallest category in terms of number of systems - have by far the most capacity and generate the most electricity. The following table illustrates the generation capacity relationships that existed within the industry for the year 1973;

GENERATION CAPACITY (1973)

Investor-Owned	Co-operatives	Publicly Owned
78%	2%	20%

These generation capacity relationships have not changed much over the years. There has been a slight shift toward investor-owned and co-operatives and away from publicly owned over the past fifteen years, but this change has been very small. The relationship among the types of utilities with respect to the production of electrical energy has followed a pattern nearly identical to that shown above for generation capacity. That is, investor-owned utilities generate about 78 percent of all the electrical power in the United States, while co-operatives and publicly owned utilities generate about 2 percent and 20 percent respectively.

The generation facilities of the electric utility industry can be divided into four general types, depending entirely upon the kind of prime mover used to drive the generator. These four are as follows: fossil fuel-steam, hydraulic, nuclear-steam, and internal combustion. The relationships and the changing nature of these relationships are shown in the following brief table:

GENERATION BY TYPE OF PRIME MOVER

Year	Fossil-Steam	Hydraulic	Nuclear-Steam	Internal Cumbustion
1960	79%	19%	-	2%
1973	80%	14%	5%	1%

This shift towards nuclear and away from hydraulic installations has been accelerating in recent years, not because the country's hydro-electric capacity is being reduced,but because the rate of new hydro-electric additions is much slower than the rate of growth of nuclear capacity additions. The trend toward nuclear generating stations is expected to continue, and some observers believe that nuclear could account for as much as 20 percent of total generating capacity by the early 1980s.

The relationships in the kind of fuel used in the generating stations throughout the country have changed in the past years, although coal still makes up by far the largest portion of the fuel used by the industry. The following brief table illustrates these changing relationships:

GENERATION BY TYPE OF FUEL

Year	Coal	Oil	Gas	Nuclear
1960	66%	8%	26%	-
1973	54%	20%	21%	5%

Much of this shift in the fuel mix toward oil has been brought on by the need to burn low sulfur fossil fuels and by the increasing shortage of natural gas. State and local environmental restrictions required the use of low sulfur fuels, a requirement much more easily met with oil than with coal. In addition, the abundance of residual fuel oil refined from low priced foreign crude oil - particularly on the East Coast - hastened this trend. With respect to natural gas, electric utilities have been low priority users and are suffering severe curtailments as the shortage deepens. In light of the costs and availability of fossil fuels, however, it is likely that the beginning trend toward nuclear fuel will continue and even accelerate, while oil will decline in importance.

THE SECURE YEARS - 1960-1966

Beginning with the time when statistics for the electric utility industry began to be kept, electrical energy production never failed to double every nine or ten years. That kind of growth in the demand for energy, together with improving technology and receptive capital markets, made this industry very dynamic. Not only were the trends favorable, but the predictability of the key factors affecting the industry was high. Load characteristics were well understood and variability from historical trends was small. Capital investment planning presented few difficulties. The various cost factors were under control, generally declining, and predictable. Given the regulatory climate, revenues were also predictable. Finally, all this added up to good financial results for the industry - and a good reception in the capital markets.

DEMAND PREDICTABLE

The demand in very few industries was as predictable as that in the electric utility industry, and very few utilities had difficulties with their projections. Beginning in 1960, and continuing until 1966, for instance, total consumption of energy in the entire industry grew at a relatively constant average annual rate of 6.9 percent. The year-to-year increase ranged only between 5.5 percent and 7.7 percent, and the last three successive years very nearly had identical increases. At the company level, of course, more variability occurred, but even there, much of the variation was the result of factors such as growth in population, growth in households, industrial activity and the like - things well known to the individual utilities. Inability to forecast the growth in energy consumption was not a pressing problem of the day.

In a similar fashion, forecasting peak demand posed no more serious a problem. Throughout the early 1960s, the annual non-coincident peak load[1] for the industry as a whole grew at an average annual rate of 7.0 percent, and the growth percentage ranged only from 6.0 percent to 8.5 percent - a relatively narrow range, particularly when compared to the events of subsequent years. Once again, individual companies experienced a similar narrow range of growth in their annual non-coincident peaks. Exhibit 1 illustrates the relative predictability of growth in both total energy and peak demand. In 1966, things began to change and real uncertainty became a factor.

---

[1] *The annual non-coincident peak load is the higher of the two non-coincident peak loads reported by the Edison Electric Institute - summer and December - each of which is the sum of the peak loads of all systems during that time period without respect to the particular day it may have occurred in each system.*

Because growth in both consumption of energy and peak load were so predictable, so too was annual load factor.[2] Load factor for the industry experienced virtually no changes through the early 1960s, going from 65.5 percent in 1960 to 65.0 percent in 1965 and never varying far from that range. Exhibit 2 illustrates the remarkable stability in load factor experienced by the industry.

INVESTMENT PLANNING NOT DIFFICULT

Throughout the early part of the 1960s, capital investment planning presented few difficulties. This exercise, of course, begins with the forecast of energy demand and peak load for several years ahead - and growth in these two key areas was relatively predictable. So energy and peak load requirements were known with a high degree of certainty. In addition, the kind of capacity to add was not much of a mystery in those days. Utilities were adding large baseload plants to achieve the economies of scale available to them, retiring their older, less efficient plants or reducing them to cyclic or even peaking use. To illustrate, peaking plants made up only 3 percent of total generation additions in the early 1960s. More recently, the appropriate mix of new capacity has become more of an issue, and peaking plants made up 17 percent of total new capacity in the past seven years. Nuclear decisions were beginning to be made by the more adventurous utilities, but very little nuclear capacity was brought on prior to 1969, and the current technical and environmental problems were not as sharply defined in those days as they are now.

---

[2] *Annual load factor is the ratio of total electric energy output for a year in kilowatt-hours to the maximum non-coincident peak load in kilowatts multiplied by 8760 (number of hours in a year) - 8,784 in leap years.*

The investment impact of adding the capacity necessary to meet the growing demand was quite predictable. First, the cost of new capacity per kilowatt was stable or declining slightly throughout the 1960s. Exhibit 3 shows that the cost per kilowatt of installed capacity was constant during the first four years of the decade, then declined somewhat for three years, and finally finished the decade at about the same cost level as it started. Second, investment in electric plant per dollar of revenue remained quite constant at around $4.46. Exhibit 4 illustrates the remarkable consistency of investment per revenue dollar through 1966. Third, capital expenditures rose a very small amount in the early 1960s. Exhibit 5 indicates that these expenditures rose from $3.3 billion in 1960 to $4.0 billion in 1965, an average annual increase of only 4.0 percent over the period. Given this stability and the techniques available to project capital expenditures for new capacity, industry members were able to forecast capital needs with a high level of confidence.

COSTS UNDER CONTROL AND PREDICTABLE

Throughout the early years of the 1960s, the cost of producing and distributing electricity declined slowly but surely. Thus, the ability of utility managements to predict and project their costs was very good. Exhibit 6 shows that the total cost per kilowatt-hour (defined as operating revenue less net income from sales of electricity - thus, the figure represents all costs associated with the generation and sale of electricity) declined consistently from 16.3 mills per kilowatt-hour in 1960 to 14.9 mills in 1966.[3] Much of the decline resulted from reductions in the per kilowatt-hour cost of two major cost components: operations and maintenance, and interest - also shown in Exhibit 5. The remainder of the decline was due largely to a reduction in the per kilowatt-hour cost of taxes, both income and non-income.

The reduction in operations and maintenance cost was due in large part to the economies of scale resulting from the newer, larger baseload plants brought on-stream during this period, and to the continually increasing electrical usage per customer. The per kilowatt-hour fuel cost declined during this period due to the combination of reduction in fuel cost per million BTUs and an improved heat rate.[4] Finally, the per kilowatt-hour costs of interest went down, this occurring in spite of a rise in the embedded interest rate from 3.6 percent to 3.9 percent during this seven year period. Growth in total energy sales greatly outdistanced this rise in interest rate, and unit cost of interest went down.

---

[3] *The data in this exhibit and in all subsequent exhibits which utilize financial analyses of balance sheet or income statement items have been adjusted by TBS to reflect electric operations only.*

[4] *Heat rate, a measure of generating station thermal efficiency, is the amount of BTUs in the fuel consumed to generate one kilowatt-hour of electric energy.*

REVENUES ALSO PREDICTABLE

The task of projecting revenues throughout this period was not difficult. Growth in electric revenues was steady and reasonably consistent, moving from $10.1 billion in 1960 to $13.4 billion in 1965, a total growth over the period of 32 percent. That growth averaged 5.8 percent per year, with year-to-year growth ranging only from 5.4 percent to 6.8 percent (see Exhibit 7). This growth in overall revenues occurred in spite of generally declining electric rates and a significantly lower revenue per kilowatt-hour (5.9 percent total decline over the period) due to more and more electric energy being sold in the lower blocks of the block rate schedules[5] prevalent in the industry. Exhibit 8 illustrates the declines in these two factors.

Revenues increased during this period because declines in rates and revenues per kilowatt-hour were more than made up by increases in the numbers of customers (extensive growth) and by increases in the average kilowatt-hour usage per customer (intensive growth).

---

[5] *In a block rate schedule, a specified charge per kilowatt-hour is made for all kilowatt-hours falling within a block of such units, with reduced charges per unit for all or any part of succeeding blocks of such units.*

Exhibit 9 indicates that the number of customers grew 11.4 percent from 1960 to 1965, and the kilowatt-hours sold per customer grew 25.3 percent - by far outweighing the 5.9 percent decline experienced in revenues per kilowatt-hour. The result was steady growth in industry revenues - consistent and reasonably predictable, even at the company level.

FINANCIAL RESULTS GOOD

The revenue growth and the cost stability and control experienced through the 1960s led to good financial results. The electric utility industry performed well in all of the usual measures of financial performance - net income, earnings per share, return on equity, and return on total investment - during this period. This performance is shown in Exhibit 10. The figures in this exhibit have been adjusted to illustrate performance on electrical plant and operations only - all gas and other operations have been taken out of these industry figures. The results are as follows:

- Net income increasing each year from $1.7 billion in 1960 to $2.4 billion in 1965, an overall increase of 42.9 percent.
- Earnings per share increasing each year from $4.12 in 1960 to $5.92 in 1965, an average annual growth rate of 8.7 percent.
- Return on equity improving significantly from 11.7 percent to 12.9 percent.
- Return on total investment also improving from 6.4 percent to 7.2 percent.

This kind of financial performance - together, of course, with the generally favorable investment climate - led to good acceptance in the financial markets for the common stocks of the utility industry. Price earnings ratios improved from 16.9 in 1960 to 19.8 in 1965. And, together with a constantly increasing book value per share, the ratio of market price of an average utility share to its book value improved from 1.69 to 2.22 during the same period. Exhibit 11 illustrates the year-to-year performance of these two indicators of investment climate.

The result of this favorable investment climate was relative latitude on the part of investor-owned utility management in financing their growth. On the whole, utility managers took a "conservative" approach, opting to use debt to finance a constant 60 percent of external requirements over the years, thereby shifting their capital structure slightly toward equity and away from debt as the availability of internally generated funds increased constantly. Exhibit 12 illustrates this small but consistent move toward equity and away from debt during the 1960-1965 period. Exhibit 13 illustrates the increasing importance of internally generated funds, along with the fact that, while debt as a portion of external funds utilized each year remained essentially constant, even it was trending downward as a portion of all fund sources as internally generated funds became more of a factor. Thus, growth financing was a relatively easy task for utility management throughout this period.

* * *

In short, the early part of the 1960 decade was a very good one for utility management. The problems that existed were predictable, manageable problems. Uncertainty was at a minimum and the trends and climate of those days made dealing with what uncertainty did exist a very reasonable proposition. Changes in the situation were in the wind, but the impacts were to be felt later.

THE TURNING POINT - 1966-1969

Everything that caused the great changes in the electrical utility industry did not happen all at once, nor did they all come from the same root factor. Rather these events occurred during the latter part of the 1960 decade, and most of the events themselves were trends that were picking up momentum during this period. Of the many things that were to have dramatic impact on this industry, five will be mentioned briefly here.

CREDIT CRUNCH

While it can be argued that the cost of money was destined to go up anyway as the economy began to overheat in the late 1960s, the credit crunch of 1966 caused a dramatic rise in the cost of money. Picking Moody's industrial bond rate as an example, this rate in 1965 had remained virtually constant for seven years. Then it moved steadily upwards until in 1970, the bond rate was almost double what it had been five years earlier (See Exhibit 14). The cost - and ultimately the availability - of debt has obvious implications to the electric utility industry. In the late 1960s began the trend and problems destined to play an enormous role in the current difficulties facing the industry.

INFLATION

Chronic inflation has been an irritant in the economy for some time, but by the late 1960s, there was no question that the rate of cost increases for most companies was outrunning productivity gains. The Vietnam war fueled the situation, sowing the seeds for a later rate of inflation that was intolerable. Most important for electric utilities, inflation was particularly felt in the capital goods industries, thereby increasing the cost of building new utility plants - an event destined to have a profound effect on the utility companies.

EQUIPMENT SHORTAGES

Parts and equipment shortages began to appear in the second half of the 1960 decade. Much of this was due to capacity shortages in an overheated economy.

The result for the electric utility industry was delays in new plant construction with the attendant higher ultimate costs that such delays invariably bring - higher capital costs because the complete project required longer financing prior to being placed in service, and higher operating costs because newer, more efficient plants did not get on-stream when expected and utilities were forced to rely on more costly older plants or more expensive purchased power in the meantime.

ENVIRONMENTAL MOVEMENT

The momentum of the environmental movement really gained steam in the late 1960s. The impact of this movement on the electric utility industry was felt in two principal ways. First, it affected the cost of fuel to utilities as state and local governments placed increasing importance on environmental protection. New York City and other cities and states placed sulfur restrictions on fuels, and these restrictions increased the cost of fuel to electric utilities. Second, environmental protection caused some delays in the construction programs of many utilities. Siting, safety, and operating permits were all problems. These delay difficulties caused higher costs for utilities in the same manner as the delays from equipment shortages mentioned earlier raised ultimate costs of plant additions.

FUEL COST INCREASES

The cost of fuel has always been an important component in the cost of electric power. And until the latter part of the 1960s the cost pressures were downward. Productivity improvements in the coal industry, together with an abundant supply of interruptible and off-peak gas, kept the prices of fuel down. Then the cost of all fuels began to rise. The closing of the Suez Canal in 1967 caused tanker rates to increase, and at about the same time, the oil exporting countries began upward revisions in both posted prices and taxes. The result, of course, was higher priced oil. The price of coal also began to go up, spurred by the rise in the price of oil and also by the need for investment to improve health and safety conditions and by the rise in foreign demand for metallurgical coal. Finally, the Federal Power Commission began to permit increases in the price of interstate natural gas. This obviously impacted those utilities dependent on that fuel source, but it also tended to release somewhat the ceiling on alternative fuels, thereby allowing the price of coal and oil to rise.

* * *

Thus, the credit crunch, inflation, equipment shortages, the environmental movement, and fuel cost increases - all events that started to be felt in the late 1960s - combined to change the electric utility industry in dramatic ways. The impact of these changes will be discussed in the following section.

THE DILEMMA YEARS - 1969-PRESENT

The result of the events of the late 1960s was a significant change in the nature of the electric utility industry. Gone is the relative certainty in the key factors affecting the industry. In that place are uncertainty and a difficult operating environment.

The events of the late 1960s impacted most severely in two ways - the requirements for external financing are up dramatically, and the costs experienced by the industry are up significantly. The following paragraphs describe the nature and effects of these two areas in more detail.

EXTERNAL FINANCING UP

By any measure the industry's use of external financing went up dramatically since the mid-1960s. Exhibit 15 illustrates that while external funds as a percent of all funds averaged about 46 percent in the early 1960s (Exhibit 13 showed that this percentage was actually trending downward), the ratio is now averaging 66 percent - and until very recently had been climbing steadily. This dramatic shift in the nature of satisfying financing requirements is probably the single most important thing to happen to the industry in recent times. There are several reasons why this occurred.

The first factor underlining the increase in external financing is an acceleration in the rate of growth of both energy consumption and peak load. Exhibit 16 indicates that where the growth in kilowatt-hours had averaged 6.9 percent in the early to mid-1960s, since that time the average year-to-year growth through 1973 has been 7.5 percent. In a similar fashion, growth in peak demand was now averaging 8.0 percent on a year-to-year basis, rather than the 7.0 percent experienced throughout the early 1960s. Thus, peak load has been growing faster than total consumption in kilowatt-hours since more and more of the consumption was occurring during peak hours. This in turn created a deteriorating load factor (65.0 in 1965 to 62.0 in 1973) and a corresponding need for proportionately more capacity than had been the case. The industry simply was being required to satisfy a significantly larger and somewhat less level appetite for electrical energy than it had been in the early part of the 1960 decade. Providing the additional capacity to meet this additional requirement for electrical energy obviously increased the industry's need for funds from some source, internal or external.

A second factor affecting the need for increased external financing was the predictability of growth in energy consumption and in peak demand - because of their potential influence on reserve margins. The primary influences affecting the desire of utility management for increased reserve margins were the greater difficulty in handling an outage with ever larger units coming on line and the unknown probabilities of nuclear plant outages. But the predictability of growth in consumption and peak load has been deteriorating since the mid-1960s, and this deterioration was to serve as an influence on utility management both to provide increased peaking capacity, thereby affecting construction plans, and to plan for an increased level of reserve margins. Exhibit 16 shows that the standard deviations[6] of the year-to-year growth rates for both energy consumption and peak load have increased significantly since that time: the variability of total consumption increasing over 60 percent and that of peak load increasing by 100 percent. All these influences worked to complicate and increase construction plans and thus financing needs.

A third factor contributing to the great increase in total financing - and thus ultimately an increase in external financing - is the dramatic rise in the cost per kilowatt of newly installed capacity. This cost had been relatively constant throughout the 1960 decade, but Exhibit 17 indicates that this cost had increased dramatically since that time. The cost per kilowatt of capacity installed in 1974 was averaging about $266 - almost double the cost of 1970. And this trend toward ever increasing unit cost of new capacity is expected to continue. A recently completed survey conducted by the Technical Advisory Committee on Finance of the current National Power Survey (TAC-Finance) indicates that new capacity recently committed to go on stream in 1980 will ultimately cost an average of $390 per kilowatt for non-nuclear plants and over $450 for nuclear plants, not including pollution control devices.

---

[6] *Standard deviation is a measure of variability of items in a series from the average of that series.*

One impact of this rise in the cost per kilowatt of newly installed capacity has been an acceleration in the rate of growth of capital expenditures being made by the industry. Exhibit 18 indicates that capital expenditures - relatively constant in the early 1960s - have grown well over threefold since that time; this growth greatly exceeds the growth in consumption of energy and in peak demand.

There are several reasons for the great rise in the unit cost of new capacity. First, general construction costs have continued their inexorable rise, and the string seems to have run out on the economies of scale in building ever larger generating facilities. Thus, there was no offset to the escalating construction costs as there had been throughout the 1960s. Second, regulatory and construction delays have increased the time needed to construct a new plant, and this lag - exacerbated by the rise in interest rates and the yearly rise in construction costs - has worked to increase the final cost of completed capacity. Third, the shifting capacity mix toward nuclear with its higher capital costs (but lower operating costs) was beginning to make itself felt in the average cost per kilowatt of installed capacity, and this fact will weigh heavily on the average unit cost projected for the latter part of this decade. Finally, investments to meet safety and pollution control requirements were also contributing to the rise in unit costs of the new capacity. Thus, costs were rising, obviously creating a need for funds proportionately greater than had been experienced in the early 1960s.

A fourth factor causing external financing needs to increase substantially in both absolute and relative terms is the simple fact that since the mid-1960s, internally generated funds (largely retained earnings and depreciation) have not been growing as fast as the requirement for funds. Exhibit 19 indicates that during the early 1960s, internally generated funds grew at an average annual rate of 6.4 percent while the need for funds grew at a rate of only 2.5 percent. And in only one of those years (1962-63) did the year-to-year growth rate of internal funds fail to exceed the growth rate for the need for funds. A great contrast has existed since then. The average annual growth of internally generated funds since 1965 has increased to 9.5 percent, but the need for funds has grown almost twice that fast - an 18.1 percent average rate over that same period. And in the eight years since 1965, the year-to-year growth rate in need for funds exceeded the growth rate in internal funds every year - often substantially - until the last two years. The difference between financing requirements and internally generated funds obviously had to be made up with external financing, and as was shown earlier in Exhibit 15, this was just exactly the case.

COSTS UP SIGNIFICANTLY

The second major area impacted severely by the events of the late 1960s was that of the costs being experienced by the industry. Costs of producing and distributing electricity declined during the early 1960s. Then these costs turned around and started to climb. Exhibit 20 indicates that the total costs per kilowatt-hour grew from 14.9 mills in 1966 to 17.3 mills in 1973, a 16 percent increase in cost after years of decline. This increase is accounted for largely by the rise in operating costs - especially fuel costs - and in interest costs. As the exhibit shows, other costs declined a total of 1.0 mills per kilowatt-hour over the period, due mostly to reduced income taxes and the increase in allowance for funds used during construction (to be treated in a later section). Thus, the increases in operating costs and interest costs are more significant than might be apparent.

Total operating costs have gone up from 8.1 mills to 10.4 mills per kilowatt-hour since 1966 (see Exhibit 20), but the great bulk of this increase is due to a 57 percent increase in the per kilowatt-hour cost of fuel. There were two reasons for this dramatic turn-around in the costs of fuel. First, the heat rate realized by the industry failed to continue its annual improvement. At best, the heat rate is now static - in fact, it has not regained the performance experienced in the late 1960s. Second and more important, fuel cost per million BTU reversed its slow decline of the early 1960s and has increased significantly since then. Exhibit 21 illustrates the turn-around in annual declines of these components of unit fuel costs. The result is much higher fuel costs per kilowatt-hour.

Interest costs per kilowatt-hour - as were shown in Exhibit 20 - have almost doubled since 1965, going from 1.1 mills to 2.1 mills in that period of time. There are two major reasons for this increase. First, the general cost of borrowing money increased significantly during this period - the industrial bond rate moved from 4.8 percent in 1965 to 7.9 percent in 1973. Second, utilities were borrowing proportionately more money during this period - Exhibit 15 indicated that the use of external funds increased from 46 percent to 66 percent - and a significant portion of those funds were debt. Thus, it was inevitable that the embedded interest rate would increase (it did - from 3.6 percent in 1965 to 5.8 percent in 1972). And total interest expense attributable to electric operations was up dramatically - $3.3 billion in 1973 compared to $0.9 billion in 1966 - an average year-to-year rate of increase of over 20 percent per year. Because the growth of energy consumption grew at an annual rate of 7.5 percent over this period, it was equally inevitable that interest costs per kilowatt-hour would also increase.

* * *

The significant increase in the use of external financing and the higher cost levels at which the electric utility industry must now operate are the primary underlying causes of the current dilemma. Simply stated, the industry cannot delay the great investments needed to maintain its service capability, but the financing of those investments is becoming increasingly difficult. There are three other factors contributing to this dilemma - each one somehow the result of the underlying causes discussed earlier and each more immediate in nature. First, the return on equity in the industry is down. Second, the market value of the industry's common shares is less than their book value. Third, growth in earnings per share is down and prospects for improvement do not appear bright. Each of these factors is discussed briefly in the paragraphs that follow.

RETURN ON EQUITY DOWN

The total earnings performance of the electric utility industry has been outstanding. Exhibit 22 indicates that net income from electric operations was $4.46 billion in 1973, double what it had been nine years earlier. Further, in recent years net income for any given year never failed to increase over the preceding year. Equally important, earnings growth within the industry accelerated. Exhibit 22 shows that while the average growth of net income in the industry had been 8.6 percent during the early 1960s, it has been 10.9 percent ever since. This impressive earnings performance is somewhat clouded, however, by the increasing role that the allowance for funds used during construction (AFDC) plays in the earnings picture.

For some years, the allowance for funds used during construction - a credit to income for the interest costs paid on funds tied up in construction work in progress - has been becoming an increasingly larger portion of net income (see Exhibit 23). In 1973, AFDC had reached a high of almost 29 percent of industry net income. The concept of AFDC heretofore has been well accepted by utilities, accounting firms and rate commissions alike - the problem is that it is a non-cash credit to net income. Therefore, the cash flow available to utilities from their earnings streams is only about 71 percent of what they report.

Although industry net income has been up very nicely in recent years (10.9 percent average annual growth), the rate of growth of equity capital was even greater. Exhibit 24 points out that utility management has not changed its capital structure significantly in recent years. Thus, equity capital - in the form of both retained earnings and funds from common stock issues - has financed its historical share of the increasingly larger construction programs. Exhibit 25 indicates that total equity has been growing at an average annual rate of 12.9 percent since 1966, significantly in excess of the rate of growth of net income. Thus, as is shown in Exhibit 26, return on equity declined from 13.1 percent in 1966 to 11.7 percent in 1973. This reduced return on equity can be attributed to regulatory lag - the tendency for rate increases granted by the commissions to lag behind the cost increases that instigated the request for rate relief in the first place. Thus, rate commissions have not moved quickly enough to prevent a general decline in the industry's return on equity.

MARKET VALUE OF COMMON SHARES BELOW BOOK

A much higher rate of return on utility industry common stock is required by investors than had been the case some years ago. This increased rate of return requirement is due to two primary reasons. First, inflation generally has driven up the rate of return on riskless securities such as government bonds. Thus, the rate of return required on common stock would be driven up correspondingly because the market place always maintains an appropriate differential between the return required of riskless securities and that required of riskier equity securities. Second, the investment community appears to be assigning a higher degree of risk to the electric utility industry than it had in the past. The increase in risk assessment obviously has its roots in the uncertainty that now pervades the industry - what will earnings do, what will regulators allow, will consumers revolt over fuel cost pass-throughs, and the like? Exhibit 27 indicates that the price earnings ratio has gone from an average 19.8 in 1965 to an average 9.4 in 1973, and more recently stood at 6.1 in June 1974. The decline in price earnings ratio is a definite indication that the rate of return demanded from the industry's common stock by the financial community has increased[7].

In the face of a higher demanded rate of return on the electric utility industry's common stock, the regulators of the industry have maintained the allowable rate of return on equity at figures close to or actually below historical levels (Exhibit 26). Therefore, the industry's equity securities began to sell at a discount from previous market levels. Exhibit 28 indicates that this discounting trend continues to this

---

7. The decline in price earnings ratio is also caused by a deterioration in future expectations for the industry's common stock by potential investors. Concern exists both over prospect for continued growth in earnings per share (discussed in the next section) and over the likelihood of a stagnant or diminished dividend in light of uncertain earnings prospects and the great demand for internally generated funds.

day, and more importantly that the industry's common stock now sells at a level below its book value. (In June 1974 the average market price of common stock was very close to half of book value.) Issuing common stock at a time when the market value is less than book value dilutes earnings per share and contributes to driving the market price per share down even further.

EARNINGS PER SHARE GROWTH DOWN

The growth in earnings per share in the electric utility industry has taken an abrupt turn in the last decade. Exhibit 29 indicates that the earnings per common share have been increasing at an average annual rate of 2.8 percent since 1966, this comparing with an annual growth rate of 8.7 percent during the 1960-65 period. This slowdown in the growth rate of earnings per share - in spite of an acceleration in the growth rate of total net income - is due to two factors. The first is the decline of return on equity discussed earlier. The second factor is that the increase in outstanding shares of common stock has been almost as great as the rate of growth of net income in the industry. The average annual increase in the number of outstanding shares of common stock in the industry has been just over 7.5 percent since 1966. This compares with an average increase in total industry net income of 10.9 percent annually (Exhibit 22) during the same period. Thus, a large portion of the incremental earnings in any given recent year was needed simply to assure the maintenance of current earnings per share for the newly issued stock. By contrast, the annual increase in common shares during the early 1960s was about 2 percent compared to an annual net income growth of 8.6 percent - thus, in that period the great bulk of incremental earnings went to increase overall earnings per share, not just to cover new common shares.

Prospects for an improved earnings per share growth picture do not appear bright. Net income for the industry is highly likely to continue its growth, but the amount of new equity that must be issued to cover the capital expenditure programs - at a time when the common stock sells below book value - will only serve to dilute the growing net income even further. A deteriorating earnings per share, rather than a reduced but positive growth, may characterize the industry in the years ahead. And 1973 bore that out, with average earnings per share of $7.55 compared to $7.73 the year before.

SUMMARY

Thus, utility management presently finds itself confronting a painful dilemma. They must make enormous investments in facilities, and they must raise large amounts of external funds to finance this investment. They cannot increase significantly their use of debt or preferred stock - capital structures must be kept balanced and earnings coverage requirements must be met. That leaves no alternative save the issue of common stock.

Yet if they issue common stock, they do so at a discount to book value, thereby diluting earnings further. And the diluted earnings may serve to cause additional deterioration in the investment community's assessment of future earnings prospects and risk in the utility industry, thus further reducing the ratio of market price to book value of common stock. The result is a snowballing effect. The more common stock that is issued, the lower its price, and the more shares that must be issued. And so on it goes.

Looking to the future, even more uncertainty looms for the electric utility industry. Plant expenditures per kilowatt seem certain to escalate, but estimates are highly uncertain. Construction delays for such reasons as inter-regulatory problems, non-availability of equipment, technical problems, and pollution control problems may well continue, even accelerate. Financing the great requirements of the industry has no easy solution - particularly when the near-term outlook for the industry is in the hands of forces external to utility management.

Of the many forces acting upon the electric utility industry, three deserve specific mention. The first is the combination of forces which determine the prices of energy supply. The industry itself has very little influence on the prices it must pay for fuel. Yet, the recent rapid escalation in the prices of fossil fuels, together with the fuel adjustment clauses which pass these increases on to consumers, has aroused an adverse public opinion which could result in a significant movement toward public ownership. A second external force is the economic climate to which the capital markets respond. To meet its financing requirements over the years ahead, the industry requires both a resurgence of investor confidence and a relaxation in long-term interest rates. This climate can be affected only by public policy makers outside the industry. A third external force affecting the outlook for the electric utility industry is in the hands of those who establish regulatory policy. The existing regulatory climate exhibits no unifying structure, and as evidenced by inadequate allowed returns and declining actual returns, is detrimental to the continued viability of the industry in its existing form.

It is within this industry context that the following analysis of the impact of the Federal Water Pollution Control Act should be evaluated.

II. BASELINE ELECTRIC UTILITY INDUSTRY PROJECTIONS (1974-1990)

INTRODUCTION

In order to discuss the economic and the financial implications of the Federal Water Pollution Control Act (Act) and its final guidelines, it is important to establish a point of reference from which comparisons can be made. In doing so, the uncertainties inherent in forecasting conditions within the electric utility industry which are unrelated to the Act should be segmented from those associated with the Act. This reference point requires the establishment of a set of baseline conditions which exclude any impact associated with existing state and local environmental standards, as well as federal standards as specified in the Act and the Clean Air Act of 1970, as amended.[1] Thus, the baseline projections represent what utilities would expend in the absence of environmental regulations.

The baseline projections to be described in this report closely parallel the operating and financial assumptions employed by the National Power

---

[1] *The following analysis does not consider the economic impacts associated with the Clean Air Act of 1970 or any other environmental legislation not directly related to the Water Act.*

Survey's Technical Advisory Committee on Finance (TAC-Finance). In fact, all operating and financial assumptions not directly related to pollution control equipment were those specified by the TAC-Finance.[2]

The research methodology to be employed herein is based upon a computerized model of the electric utility industry which was developed by Drs. Howard W. Pifer and Michael L. Tennican of Temple, Barker and Sloane, Inc. (TBS). This model - entitled a Policy-Testing model (PTm) - is one of a series of industry models developed by TBS to project the economic and technical implications of alternative policy options in the form of industry structure, rates and method of expansion, financial strategies, regulatory actions, taxation policy, economic conditions, etc. PTm (Electric Utilities) was initially developed to provide industry-wide projections for the above-mentioned TAC-Finance. Appendix A provides a non-technical overview of the logical structure of this computer-based model.

In projecting future operating and financial conditions within the electric utility industry, TBS by necessity had to develop its initial estimates in current dollars - that is, expenditures in 1980 were measured in 1980 dollars. Since depreciation, interest charges, and net income allowed are determined primarily by historic costs while other expense items are determined by current cost levels, all financial transactions within PTm are in current dollars. Likewise, all operating and financial assumptions have been reported in current dollars. However, all economic and financial implications summarized in this report have been converted to 1974 constant dollars in order to provide a frame of reference for comparisons. This conversion from current to constant dollars utilized the overall 5 percent inflation factor proposed by the National Power Survey for planning purposes.[3] In order to minimize the possible misinterpretations of the results of this study, all exhibits will be clearly marked as to the dollars employed, and amounts reported within the text will be constant 1974 dollars unless otherwise specified. In general, the following rules of thumb will be employed in the exhibits:

---

[2] *These assumptions correspond to those incorporated into the TAC-Finance Cases I and IA.*

- operating and financial assumptions will be projected in current dollars, and
- economic and financial implications will be reported in constant 1974 dollars.

The initial conditions for the industry were developed from the most recently published data - from 1972 Federal Power Commission's *Statistics of Privately-Owned Electric Utilities in the United States*. With these published data as the basis for the investor-owned sector, the TAC-Finance estimated that the public sector would be represented as one-fourth of the investor-owned sector.[4]

---

[3] *While this long-run inflation factor may appear somewhat low in comparison with current rates, all cost escalation factors were developed relative to this rate. Thus, a shift in the underlying inflation factor would impact all of the other escalation factors, and would have an insignificant impact on these data reported in constant 1974 dollars.*

The remainder of this chapter will specify the operating and financial assumptions which comprise the industry baseline conditions, project the economic and financial implications that follow from these assumptions, and compare these projections with those based upon the historic industry growth rate. The baseline conditions developed in this chapter will then serve as the basis for an evaluation of the relative impact of the final guidelines in later chapters.

INDUSTRY STRUCTURE

The electric utility industry is actually the aggregation of two principal sectors[5] which, while providing essentially the same service, differ significantly in structural characteristics. These sectors are the investor-owned (i.e., private) firms and public agencies (i.e., federal, state and municipal). In addition, there are fundamental accounting differences between those investor-owned utilities allowed by their regulatory commissions to normalize income tax expenses and those firms required to flow through the benefits of accelerated depreciation and other tax deferrals.

---

[4] *This 80-20 mix differs slightly from the actual industry relationship reported in Chapter I. For this reason, industry totals reported herein may differ slightly from actual results prior to 1974.*

[5] *For purposes of projecting industry trends, the TAC-Finance arbitrarily included co-operative utilities within the public sector. In addition, the basis for the initial conditions within the private sector is the Class A and B investor-owned utilities.*

In order to develop industry-wide projections, the TAC-Finance assumed the following industry structure with respect to the mix of public and private firms, as well as the proportion of states (weighted by size) which require investor-owned firms to employ flow through accounting procedures:

● publicly owned	20 percent
● investor-owned	80 percent
--normalized accounting	(48 percent)
--flow through accounting	(32 percent)

Given the relative importance of the utilities in the private sector and the paucity of cogent information on the financial characteristics of those in the public sector, the two segments of the private sector are modelled in detail and together serve as a basis for estimating certain characteristics of the public sector.

Electrical energy historically has been generated primarily by fossil-fueled steam electric plants - coal, oil and gas - nuclear steam electric, hydroelectric and peaking units (internal combustion and gas turbines). Recent trends and future projections suggest that a major source of future generation will be nuclear-fueled. For this reason, the TAC-Finance segmented generation capacity into two categories: nuclear and non-nuclear.[6]

GENERATING CAPACITY

Perhaps the most critical set of assumptions made by the TAC-Finance relates to the rate of growth for the electric utility industry in the period through 1990. Until the recent "energy crisis," industry observers assumed that the current rate of growth - which implied a doubling in size each decade - would continue through the 1970s with a gradual decline coming during the 1980s. Events during the winter of 1973-74 have altered these assumptions so that most observers now forecast a moderation in the rate of growth.[7] For these reasons, the TAC-Finance lowered its most-likely estimate of future growth from the historic rate of growth.

---

[6] *This latter category must be further refined in order to isolate the proportion of non-nuclear (i.e., fossil-fueled steam electric) capacity which may require pollution control equipment.*

[7] *Electrical World, which publishes a comprehensive forecast each year, has substantially lowered its most recent forecast (15 September 1974).*

In addition to assuming that the long-run rate of growth would be moderate, the TAC-Finance attempted to estimate the short-run implications of the recent Arab oil embargo and its related impacts. These short-run aberrations could affect any or all of the following:

- rate of growth in peak load demand,
- peak load reserve margins,
- rate of retirement for generation capacity,
- mix of nuclear and non-nuclear generation capacity additions, and
- capacity factors.

The TAC-Finance assumed that the growth in peak load would be dramatically reduced from the growth rate in excess of 9 percent that prevailed in the early 1970s. The growth in peak load was assumed to drop off to 1 percent in 1974 with a gradual improvement to 4 percent in 1975 and 6.5 percent for the remainder of the decade. Peak load growth in the 1980s was assumed to decline to 6 percent in the early 1980s and 5.5 percent in the latter half of the decade.

With the sudden decline in the peak load growth rate, reserve margins were expected to increase from 20 to 26 percent by 1975 because the generation capacity under construction could not, in the short run, be delayed. Construction would, however, be curtailed for those units planned to be placed in service in the late 1970s, thus permitting reserve margins to gradually return to approximately 20 percent. Exhibits 30 and 31 provide the detailed factors which impact the growth of generation capacity and the resultant capacity additions, retirements and totals.

During the period 1974-77, generation capacity will increase by nearly 100 million kilowatts - an annual growth rate of 5.3 percent. Another 200 million kilowatts will be added during the 1978-83 period with an annual growth rate of 5.7 percent. By 1990 generation capacity will exceed one billion kilowatts, an increase of 5.6 percent per year and an increase in generation capacity of nearly 340 million kilowatts during the 1984-90 period.

These net additions to generating capacity include the retirement of obsolete non-nuclear generating capacity assumed to retire at the rate of:

• 1974-75	0.4 percent per year
• 1976-80	0.7 percent per year
• 1981-90	1.2 percent per year

While much publicity has preceded the construction of nuclear-fueled generating plants, a small percentage of the generating capacity in service in 1973 was nuclear-fueled. Although environmental and technical issues have delayed the conversion to a nuclear-based electric utility industry, the TAC-Finance has assumed that the mix of generating capacity will steadily shift to nuclear generation. Specifically, the TAC-Finance has assumed that the mix of generating capacity additions will be:

●	1974-75	30 percent nuclear/ 70 percent non-nuclear
●	1976-80	40 percent nuclear/ 60 percent non-nuclear
●	1981-85	50 percent nuclear/ 50 percent non-nuclear
●	1986-90	60 percent nuclear/ 40 percent non-nuclear

The growth in sales of electricity to ultimate consumers differs from the growth in capacity due to the assumptions regarding capacity utilization as measured by the capacity factor. The TAC-Finance assumed that the demand for electricity will decline somewhat between 1973 and 1975 due to a decline of approximately 10 percent in the capacity factor. This drop in generation efficiency results from the above-mentioned decline in peak load growth and the corresponding inability to curtail construction in the short run. The industry's response to the energy crisis is manifested in the sharp improvement in the late 1970s and the return to a capacity factor of nearly 50 percent during the 1980s. Exhibits 30 and 31 provide the year-by-year capacity factor assumptions and the resulting growth in electricity sales to ultimate consumers.

CAPITAL COST FACTORS

In an effort to assess the capital cost escalation facing the electric utility industry, the TAC-Finance conducted an informal survey of existing utility construction plans through 1980. The survey covered 20 utilities which were constructing a total of 75 generating units during this period. On the basis of this survey, the TAC-Finance developed the cost growth factors detailed in Exhibit 32. The general inflation rate of 5 percent proposed by the National Power Survey for planning purposes was then used as the basis for cost growth for transmission and distribution and as the basis for post-1980 inflation in the costs of generation capacity.

Although the generating capacity, related transmission and distribution equipment, and nuclear fuel placed in service in any given year is determined by the peak load and reserve margin requirements, the actual construction work begins several years prior to the in-service date. Moreover, the cash flow associated with generating plant additions generally precedes the completion of construction. Changes in the related construction work in progress account historically have constituted a substantial portion of the capital expenditures by the electric utility industry in any given year.

In order to approximate the cash progress payments related to construction requirements, the TAC-Finance assumed the payment schedules outlined in Exhibit 33. For example, a $100 million nuclear-fueled generating unit (with an additional $15 million for nuclear fuel) placed in service in 1980 would require cash payments of:

	Nuclear Plant	Nuclear Fuel
1976	$25 million	-
1977	$25 million	-
1978	$25 million	-
1979	$25 million	-
1980	-	$15 million

Likewise, a $100 million fossil-fueled generating unit placed in service in 1980 with $100 million in related transmission and distribution equipment would require cash payments of:

	Fossil Plant	Transmission and Distribution
1977	$25 million	-
1978	$25 million	-
1979	$25 million	$50 million
1980	$25 million	$50 million

OPERATING COST FACTORS

In addition to capital expenditures, a primary target of cost inflation has been operations and maintenance expenses which include expenditures for fossil fuels. Prior to the recent "energy crisis" the cost growth of operations and maintenance expenses for non-nuclear generation approximated 10 percent, while operations and maintenance expenses for nuclear generation (excluding fuel) were relatively stable. With the rapid increase in the price of petroleum products resulting from the oil embargo, the limited supply of natural gas and significant disparity between inter- and intra-state natural gas prices, and the steady increase in coal prices, the TAC-Finance assumed that operations and maintenance expenses associated with non-nuclear (primarily fossil-fueled) generation would escalate at 20 percent during 1974 and 15 percent in 1975 before falling to 8 percent in the late 1970s. At that time, these expenses were assumed to increase steadily at the long-run inflation rate of 5 percent. In addition, operations and maintenance expenses for nuclear generation (excluding fuel) also were assumed to escalate at the 5 percent rate. Exhibit 34 details these expenses.

FINANCIAL POLICY PARAMETERS

The instruments employed to finance the expansion of the electric utility industry depend largely upon the financial policies of the electric utilities and the policies of the governing regulatory agencies. These financial parameters are especially prominent in any projection of the electric utility industry with its long lead time for construction of generation plant and its capital intensity.

CAPITALIZATION

In projecting the capital structure of the industry, the TAC-Finance assumed that the capital structure will remain relatively stable. The mix of financing instruments for investor-owned utilities, therefore, is determined within PTm by the following constraints upon their capital structure:

●	long-term debt	no more than 55 percent
●	preferred stock	no more than 10 percent
●	common equity	at least 35 percent

In addition to projecting the capital structure, one needs to forecast the future cost of each financing instrument.

Historically, the average rate of interest on long-term debt and the dividend rate on preferred stock have been approximately the same. At the end of 1972, the embedded rate for each was approximately 5.5 percent, a rate significantly below the existing long-term rate of interest. Acknowledging this fact, the TAC-Finance assumed an 8 percent rate for interest on long-term debt and dividends on preferred stock for its projections. Without a significant change in the mix of financing instruments, the return on common equity, the common stock dividend payout ratio, or some combination of these factors, these conditions wherein the marginal debt rates exceed the embedded rates will result over time in lower interest and preferred dividend coverage ratios.[8]

In addition, the TAC-Finance assumed that average consumer charges per kilowatt-hour will be set at levels which yield a 14 percent return on common equity. It should be noted that this assumption is consistent either with a target 14 percent return and no regulatory lag or a target rate in excess of 14 percent with time lags in the regulatory process.[9] In addition, a stable dividend policy which results in a 70 percent dividend payout ratio was employed.

---

[8] *For example, the assumptions implicit in these baseline conditions result in the interest coverage ratio, defined as Earnings Before Interest Charges and Income Taxes divided by Interest Charges, declining from 3.9 in 1974 to 3.1 in 1990.*

Regulatory agencies in the past have required electric utilities to capitalize a portion of the financing charges associated with the funds tied to construction work in progress. In 1972, the allowance for funds used during construction (AFDC) approximated 6.4 percent of construction work in progress. The TAC-Finance projected this constant rate for AFDC.

For the public sector, the TAC-Finance simply assumed that 65 percent of total financing requirements will be met from external sources.

ACCOUNTING PRACTICES

Internal cash generation in an industry as capital intensive as the electric utilities depends heavily upon the accounting procedures employed. As previously mentioned, this analysis assumes that the electric utility industry is segmented into public and investor-owned firms with the latter group of utilities further divided into those which are required to use normalizing techniques and those which use flow through accounting procedures. While alternative accounting practices change significantly both the timing of the cash flows from generating capacity additions and the revenues required, the actual liberalized depreciation policies and investment tax credit policies apply equally to both groups.

---

[9] *In recent years the actual return on common equity has been between 11 and 12 percent. Previous analysis for the TAC - Finance has shown that varying the required rate of return on common equity, while perhaps affecting the ease with which additional financing can be obtained, has minimal impact upon the amount of additional financing required.*

The TAC-Finance assumed straight-line depreciation over 33 years for regulatory and financial accounting purposes. Tax depreciation figures are the maximum allowed and make use of the asset depreciation range (ADR) and the double-declining balance depreciation provisions within the tax code. An exception to the above is nuclear fuel which is depreciated on a four year, straight-line basis for both tax and regulatory purposes. In addition, a 4 percent investment tax credit is permitted on 80 percent of capitalized expenditures.

TAXES

Taxes within PTm have been segmented into federal and state income taxes as well as additional taxes other than on income. In developing its projections the TAC-Finance specified these tax rates in the following way:[10]

● federal income tax rate	48.0 percent
● state (and local) income tax rate	4.8 percent
● other taxes as a percent of revenues	10.5 percent

As has been outlined above, the operating, financial, tax, regulatory, and accounting parameters and constraints relevant to making economic and financial projections for the industry are individually rather simple. However, because of interactions among the various industry relationships and constraints, attempts to reduce the number of factors through shortcut approximations are hazardous.[11] Furthermore, such shortcuts - even if based on careful econometric analyses of historical data - would tend to preclude an examination of implications of structural and policy changes.

---

[10] *An example of the reconciliation of taxes within PTm is provided in Appendix B.*

[11] *To illustrate the point concretely, consider the industry's effective tax rate as it appears in regulatory and shareholder financial reports. This rate is, in fact, a complex function of (among other things): the actual federal, state, and local income tax rates; the industry's plant and equipment expenditures in the current and past years; and the reduced asset lifetimes, the accelerated methods of depreciation, the investment credits, and the other income statement items allowed for tax purposes but not for regulatory purposes. These current and past expenditures are themselves a function of: demand growth, the mix of nuclear and non-nuclear capacity built to meet this demand, and the costs per unit of such generating capacity and the related transmission and distribution equipment. Clearly, to assess the industry's future effective tax rate directly is a formidable task; even more clearly, simply to assume the future rate will be the same as the current rate or some average of recent rates is unlikely to be an adequate approximation of the outcome of the detailed calculations or actual events.*

ECONOMIC AND FINANCIAL IMPLICATIONS

The preceding assumptions regarding generation capacity, capital and operating cost factors, and financial parameters define the baseline conditions for the electric utility industry. Exhibit 35 provides selected summary data in constant 1974 dollars for specific years. In addition, Appendix B provides an example of the level of detail captured by PTm.

CAPITAL EXPENDITURES

Capital expenditures are defined as the sum of expenditures for plant and equipment placed in service and the change in construction work in progress (CWIP) during any given year. For example, the baseline projections for the next decade (1974-83) indicate that capital expenditures will be $203.2 billion in constant 1974 dollars. This amount can be further segmented into $179.0 billion for plant and equipment placed in service during the period plus an increase in CWIP of $24.2 billion. These latter expenditures should be allocated to the future period in which the equipment is placed into service.[12]

---

[12] *This adjustment to capital expenditures - while not done in the summary data exhibits - will be explicitly included in the tables referenced throughout the text.*

EXTERNAL FINANCING

External financing requirements are the sum of long-term debt, preferred stock and common stock issues in any given year, including the refinancing of maturing long-term debt.[13] These requirements during the next decade are expected to total $126.3 billion in constant 1974 dollars - approximately 62 percent of total capital expenditures during the same period. The difference between capital expenditures and external financing requirements in any given year is the amount of funds generated internally in the form of retained earnings, depreciation and tax deferrals less the refundings of long-term debt.

OPERATING REVENUES

Operating revenues in the investor-owned sector are those required to yield a 14 percent rate of return on average common equity. Public sector revenues are then based on the same revenue per kilowatt-hour. In 1983, total operating revenues are projected to be $74.7 billion in constant 1974 dollars.

O/M EXPENSES

Operations and maintenance expenses include

---

13. A schedule of long-term debt refundings through 1990 has been estimated from published sources and in no year exceeds $1.7 billion. Further, the TAC-Finance assumed that no new long-term debt issues will mature prior to 1990.

those items so defined by the Federal Power Commission in its *Statistics of Privately-Owned Electric Utilities in the United States* with the exception of nuclear fuel. For example, the 1983 operations and maintenance expenses are estimated to be $38.0 in constant 1974 dollars.

CONSUMER CHARGES

Consumer charges are the average amount per kilowatt-hour which is being paid in any given year. The amount of electrical energy consumed is based upon the growth in peak load demand, the reserve margin and the capacity factor. For example, the 1983 sale of electrical energy to ultimate consumers amounts to 3160.8 billion kilowatt-hours and is obtained from:

- 1973 peak load demand of 351.8 million kilowatts,
- growth in peak load demand between 1973 and 1983 of approximately 5.5 percent per year,
- reserve margin of 20 percent,
- capacity factor of 49.9 percent, and
- 8760 hours per year.

The average consumer charge per kilowatt-hour is then obtained by dividing operating revenues by the total electrical energy consumed. The average cost of electricity in 1983 is projected to be

23.6 mills per kilowatt-hour.

SUMMARY OF BASELINE CONDITIONS

The following brief table summarizes the industry baseline conditions for selected time periods.[14]

BASELINE CONDITIONS
(1974 Dollars)

	1974-77	1974-83	1984-90
Capital Expenditures in billions	$53.4	$179.0	$219.8
External Financing in billions	35.8	126.3	146.3
O/M Expenses in billions	92.0	292.5	311.2
Consumer Charges in mills/KWH at end of period	24.0	23.6	22.4

Thus, even without the added expenditures required to meet the Act's effluent guidelines, the industry is expected on an annual basis to expand as follows:

---

[14] *These same time periods will be employed throughout the subsequent analysis of the Federal Water Pollution Control Act.*

RATES OF GROWTH IN SELECTED STATISTICS
(1974 Dollars)

	1974-77	1974-83	1984-90
Electric Energy	4.3%	5.5%	5.6%
Generation Capacity	5.3	5.7	5.6
Capital Expenditures	6.5	7.4	4.7
External Financing	7.8	8.4	4.1
Operating Revenue	7.4	6.6	4.9
O/M Expenses	10.5	7.9	3.8
Consumer Charges	2.9	1.0	-0.7

The moderation of the growth in electric energy is somewhat offset by the short-run increase in reserve margins and decrease in capacity factors. The growth of both electric energy and generation capacity in the 1980s are equivalent due to a return to stable reserve margins and capacity factors. The capital expenditures required by the industry in the next decade are projected to grow at a rate in excess of capacity additions since cost escalation in the construction industry is expected to exceed the economy's overall rate of inflation. Likewise, external financing requirements during the next 10 years will continue to rapidly escalate due to the assumed growth in cost factors and the inability of the industry to increase its internal cash generation under existing government policies. As inflation abates and stability returns to the electric utility industry in the 1980s, the growth rate of capital expenditures and external financing will slacken.

Operating revenues are projected in the short run to increase by approximately 7 percent due to the rapid, near-term escalation in the price of fossil fuels and the limited utilization of nuclear generation. In the 1980s - with the reversal in these two trends - the growth in operating revenues will subside to a rate less than that of electric energy. Thus, the average consumer charges in constant 1974 dollars per kilowatt-hour will actually decline during the 1980s after a mild rate of increase in the next decade.

HISTORIC GROWTH ASSUMPTIONS

All of the above results were based upon a moderation in the historic rate of growth within the industry. Prior to this report and the forthcoming TAC-Finance report, TBS analyses for both the National Power Survey and EPA were based upon an historic rate of growth. While the TAC-Finance develops the implications of this rate of growth in its Case 2, the committee no longer believes that these assumptions represent the most-likely set of industry projections.

In order to provide continuity among reports and to detail the economic and financial implications of a moderation in industry growth, TBS analyzed the generation capacity growth assumptions contained within the TAC-Finance Case 2. It should be noted, however, that the historic growth assumptions differ from those previously reported in EPA's *Economic Impact of Proposed Effluent Guidelines - Steam Electric Power Generating (March, 1974)* since they also reflect the short-run impact of the recent "energy crisis." In representing the case with historical industry growth, the TAC-Finance assumed that peak load would decline to 3 percent in 1974 and 5 percent in 1975 before returning to the historic rate of doubling every decade (that is, 7.2 percent per year) for the remainder of the 1970s. Peak load growth in the first half of the 1980s was assumed to decline to 6.7 percent with a slight erosion to 6.6 percent in the second half of the 1980s.

With the near-term decline in peak load growth, reserve margins were projected to increase to 28 percent by 1975 as generation construction could not be delayed in the short run. Reserve margins were expected to steadily decline to 20 percent by the beginning of the 1980s. Exhibits 36 and 37 provide the detailed factors which impact the growth of generation capacity and the resultant capacity additions, retirements and totals. The following brief table compares these differences for selected periods:

NET CAPACITY ADDITIONS
(Millions of Kilowatts)

	1974-77	1978-83	1984-90
Historic Growth	125.7	237.4	445.2
Moderate Growth	97.5	203.5	339.0
Absolute Difference	28.2	33.9	106.2
Percent Difference	22.4%	14.3%	23.9%

The overall reduction in capacity additions between historic and moderate growth range from 20-25 percent in both the short and long run with a reduced difference in the late 1970s and early 1980s. Overall, these differences result in approximately a 9 percent reduction in the total generation capacity of the industry during the next decade and a reduction of nearly 16 percent by 1990.

With the exception of a slight difference in the capacity factor during the late 1970s, no other differences in industry operating and financial conditions were varied between the moderate and historic growth scenarios.

Exhibit 38 displays the detailed economic and financial projections based upon an historic growth rate for selected years, while Exhibits 39 to 41 summarize the impact of reduced growth for selected years. While many comparisons could be made between the alternative growth rate assumptions, perhaps the most important ones - in terms of evaluating the impact of the Act's effluent guidelines - are the reductions in capital expenditures and external financing requirements associated with a moderation in the rate of demand growth as the following brief tables summarize:

CAPITAL EXPENDITURES
(Billions of 1974 Dollars)

	1974-77	1974-83	1984-90
Historic Growth	$72.9	$241.2	$314.0
Moderate Growth	60.3	203.2	238.2
Absolute Difference	$12.6	$ 38.0	$ 75.8
Percent Difference	17.3%	15.8%	24.1%

EXTERNAL FINANCING
(Billions of 1974 Dollars)

	1974-77	1974-83	1984-90
Historic Growth	$45.4	$154.4	$201.2
Moderate Growth	35.8	126.3	146.3
Absolute Difference	$ 9.6	$ 28.1	$ 54.9
Percent Difference	21.1%	18.2%	27.3%

As these tables indicate, the moderation in demand growth has a significant impact upon the investment levels required in the next decade - and an even greater impact in the long run. Given the changing nature of the electric utility industry described in the previous chapter, this decline in the rate of growth should ease the financial problems facing the electric utility industry.

In addition, this reduction in industry growth should be compared to the additional requirements imposed by the effluent guidelines - to be detailed in the following chapter - in order to determine the degree to which these environmental requirements exacerbate the previously-mentioned problems now evident within the electric utility industry.

III. ANALYSIS OF THE FINAL EFFLUENT GUIDELINES

INTRODUCTION

On 8 October 1974, the Environmental Protection Agency published in the *Federal Register* *(39 FR 36186)* final effluent guidelines and standards for steam electric power generation. These final guidelines differed markedly from the 4 March 1974 announcement of proposed rulemaking in the *Federal Register* *(39 FR 8294)*.

These modifications to the guidelines were based, in part, on the following analyses:

- economic analyses performed by Temple, Barker and Sloane, Inc. (TBS) and herein contained,
- analyses of environmental risk for alternative effluent limitations performed by Energy Resources Company, Inc. (ERCO), and
- comments submitted by the Utility Water Act Group (UWAG).

The next five chapters provide, on a consistent basis, the different analyses of economic costs and environmental risk which were performed to assist EPA in its

Preceding page blank

rulemaking. This report does not reference the independent analyses which were performed by EPA personnel and which formed the basis for the alternative policies and operating assumptions examined.

This chapter describes the operating and financial assumptions upon which the final guidelines were based and provides the resulting economic analyses both before and after consideration of exemptions under Section 316(a) of the Act and after consideration of those utilities who are in the process of installing closed-cycle cooling facilities for reasons other than environmental requirements. Chapter IV briefly describes the major alternatives which were evaluated in addition to the proposed and final effluent guidelines. Chapter V discusses the potential economic and financial impact emanating from environmental requirements associated with State Water Quality Standards. These three chapters comprise the bulk of the analyses which were performed for EPA by TBS.

Chapter VI details both the underlying methodology and analysis of the potential environmental risk associated with alternative effluent guidelines. The contents of this chapter are based upon *Development of Decision Rules for Granting Variances to Thermal Power Plants on a Specific Site Basis*, a report submitted to EPA by ERCO and herein summarized by TBS.

Chapter VII compares and contrasts the major operating and financial assumptions employed by EPA and UWAG. This analysis was performed by TBS with assistance from National Economic Research Associates, Inc. (NERA) who served as economic advisors to UWAG.

STRUCTURE OF ASSUMPTIONS

In an attempt to estimate the economic and financial impact of the Act, EPA first specified the technical standards which were to be required in its *Development Document of Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category (forthcoming)*. Having specified the technical standards, EPA was then asked to specify the operating and financial assumptions which best represented the requirements imposed by the final effluent guidelines and segmented into thermal and chemical discharges.

In specifying those assumptions which were most closely associated with the structure and operating conditions of the electric utility industry, EPA relied upon the assumptions of the National Power Survey's Technical Advisory Committee on Finance (TAC-Finance). These assumptions were detailed in the previous chapter. In addition, EPA specified all factors which were directly related to the effluent guidelines. These factors included (1) capital and operating costs which were based upon technical standards, and (2) capacity coverage and in service operation dates for pollution control equipment.

The specifications of these operating and financial assumptions directly related to the final effluent guidelines and technical standards have been divided into thermal and chemical categories with each then further segmented into:

- capital and operating cost factors,
- capacity coverage estimates, and
- installation schedules.

THERMAL CAPITAL AND OPERATING COST FACTORS

EPA relied upon the best available engineering estimates as the basis for the capital and operating cost factors which are detailed in Exhibits 42 and 43.

These capital cost estimates are based upon (1) a survey of costs incurred at existing plants, and (2) the incremental cost of installing mechanical draft cooling towers instead of open-cycle cooling on new units. These final cost estimates reflect the many comments which were submitted to EPA and which with minor exception (as described in Chapter VII) were acceptable to most representatives of the electric utility industry.

In specifying the capital costs associated with the installation of closed-cycle cooling processes, EPA segmented such costs into those required for both nuclear and fossil (i.e., non-nuclear) steam electric generating units; and, for each type of generation, the installation of closed-cycle cooling on:

- existing generating units and/or units under construction which were designed for open-cycle cooling - "retrofitted" units, and
- generating units under construction which were designed for closed-cycle cooling and/or are assumed to meet new source performance standards at time of in service operation - "new" units.

The capital costs per kilowatt of generating capacity are summarized in the following brief table:

CAPITAL COST OF CLOSED-CYCLE COOLING
(Expressed in 1972 Dollars/Kilowatt)

	Non-Nuclear	Nuclear
For Retrofitted Units	$20.43	$24.58
For New Units	$ 4.89	$ 3.84

These capital costs expressed in 1972 dollars were then converted to current dollars utilizing the escalation factors detailed in Exhibit 42.

Clearly, the process of installing closed-cycle cooling on units which currently have open-cycle cooling and/or which are under construction and were designed for open-cycle cooling is much more expensive than the installation cost of closed-cycle on new units. This results from the need to (1) dismantle and/or redesign the existing cooling system, and (2) absorb the total, not incremental, cost of the additional closed-cycle cooling facilities. The lower incremental cost for nuclear units being planned reflects their higher cost for open-cycle cooling - a result of plant sites located at considerable distance from sources of cooling water.

The operating costs associated with thermal guidelines represent the annual operating and maintenance expenses for the cooling equipment as well as associated replacement capacity. In estimating the operational impacts of closed-cycle cooling, EPA specified a capacity penalty of 3 percent which reflects:

- 2 percent due to increased turbine back-pressure, and
- 1 percent due to operating requirements for the cooling tower.

The fuel costs employed for this analysis of operating costs were based upon: (1) an average heat rate of 10,000 BTU per kilowatt-hour, (2) a fuel mix of 80 percent coal and 20 percent oil, and (3) 1974 prices of $7.00 per barrel for oil and $12.50 per ton for coal.

The annual operating costs per kilowatt of replacement generation capacity are summarized in the following brief table:

ANNUAL OPERATING COST FOR REPLACEMENT CAPACITY
(Expressed in 1972 Dollars/Kilowatt)

	Non-Nuclear	Nuclear
For Retrofitted Units	$39.41	$39.41
For New Units	$39.43	$23.12

In determining the type of replacement capacity, EPA assumed that retrofitted units were replaced by new fossil baseload units operating at a capacity factor of 60 percent. New units were replaced by like capacity - nuclear with nuclear, fossil with fossil - operating at an estimated 70 percent capacity factor.

In addition, EPA assumed that the installation of closed-cycle cooling on existing units or units under construction but designed for open-cycle cooling would require a downtime period of one month in addition to the normal maintenance period. During this period, it was assumed that the lost generation capability would be made up by utilization of peaking capacity with an incremental increase in heat rate of 2,500 BTU/KWH (12,500 less 10,000) with the same fuel mix and fuel costs used in computing the total operating costs for replacement capacity.

These outage cost factors are summarized in the following brief table:

THERMAL OUTAGE COST FACTORS
(Expressed in 1972 Dollars/Kilowatt)

	Non-Nuclear	Nuclear
For Retrofitted Units	$1.08	$0.89

THERMAL CAPACITY COVERAGE ESTIMATES

An evaluation of the impact of the thermal guidelines should include not only those expenditures which are associated with conversion from open- to closed-cycle on units existing or under construction and with new source units, but also some proportion of those units which are under construction and designed for closed-cycle cooling wherein the cooling system design was influenced by anticipation of the Act. At the same time, however, units designed for closed-cycle cooling for reasons other than environmental (i.e., for economic reasons) should not be included in an assessment of the economic and financial impact of the Act. A majority of the units which have installed closed-cycle cooling for economic reasons have done so to compensate for an inadequate source of cooling water.

In specifying the percentage of capacity which will be required to install closed-cycle cooling to meet the thermal guidelines of the Act, EPA has segmented generating units into four major categories by date of in service operation:

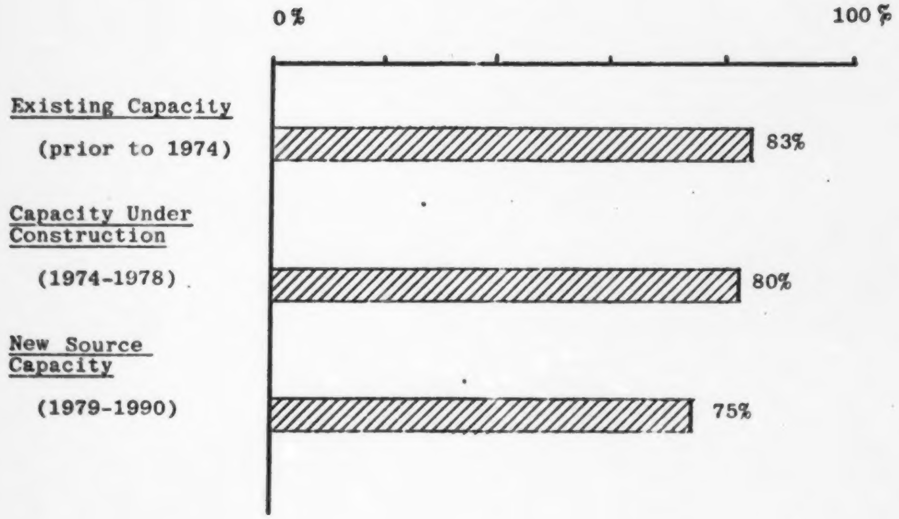
- existing units which have open-cycle cooling (placed in service prior to 1974),
- units under construction which were designed for open-cycle cooling (placed in service 1974-78),
- units under construction which were designed for closed-cycle cooling (placed in service 1974-78), and
- units assumed to meet new source performance standards at the time of in service operation (placed in service 1979-90).[1]

These categories facilitate a further differentiation of generating units into those which are required by the thermal guidelines to convert from open- to closed-cycle cooling (i.e., "retrofitted" units) and those which are designed for closed-cycle cooling for reasons related to the Act (i.e., "new" units).

---

[1] *This category was specified for analytic purposes and does not necessarily coincide with the legal definition of New Source Performance Standards (NSPS). The legal definition states that all sources which commence construction after promulgation of the final guidelines (that is, 4 October 1974) must meet NSPS.*

As previously referenced, PTm segments generating capacity into nuclear and non-nuclear units. Since the thermal guidelines impact only those units which are steam electric, EPA estimated the proportion of non-nuclear units which would be fossil-fueled, steam electric. The following figure graphically displays these assumptions:



EXISTING UNITS

The degree to which existing units would be required to retrofit mechanical draft cooling towers was a major policy variable in EPA's specification of alternative guidelines to be evaluated. EPA reviewed a number of potential criteria for exemptions from thermal control. Two criteria which were explicitly recognized in the specification of the final guidelines were the age and size of existing generating units.[2]

The proposed guidelines published in March 1974 exempted all small units (defined by the Federal Power Commission as units in plants of 25 megawatts or less and in systems of 150 megawatts or less in total capacity) and all units which were scheduled for retirement prior to 1990. The final guidelines exempt all units placed into service before 1970 from the requirements to meet the limitations on the discharge of heat. Of the units placed into operation between 1 January 1970 and 1 January 1974, only the largest baseload units (i.e., those of 500 megawatt capacity or greater) are subject to effluent control under the Act. In addition to the age of the unit, the specification of these exemptions explicitly includes unit size as a factor.

---

2. A full list of the criteria considered by EPA can be found in the Federal Register (39 FR 36188). Alternative guidelines which were evaluated by TBS are described more fully in Chapter IV.

These exemptions greatly reduce the proportion of existing units which are covered by the thermal guidelines. Based upon analysis performed by ERCO, EPA estimated that these final regulations would cover 45.8 percent of existing nuclear capacity and 4.6 percent of existing non-nuclear capacity prior to any consideration of additional exemptions under Section 316(a) of the Act.

Section 316(a) of the Act specifies that any unit can be exempted from effluent limitation which is "...more stringent than necessary to assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water into which the discharge is to be made." EPA commissioned ERCO to conduct a separate analysis of the afore-mentioned environmental risks associated with existing generating units.[3] Based upon this analysis, EPA estimated that only 12.9 percent of nuclear and 2.2 percent of non-nuclear capacity placed into service prior to 1974 (i.e., existing units) would be required to convert from once-through to closed-cycle cooling after the consideration of Section 316(a) exemptions. These capacity coverage estimates are graphically presented in Exhibits 44 and 45.

---

[3] *A summary of the ERCO analysis is provided in Chapter VI.*

UNITS UNDER CONSTRUCTION

Simply stated, all steam electric generating units placed in service on or after 1 January 1974 are required to install closed-cycle cooling. However, the impact of the thermal guidelines upon generating units now under construction must be segmented into two categories since the cost of retrofitting a unit designed for once-through cooling is significantly greater than the cost of installing mechanical draft cooling towers or an equivalent technology whenever the unit was designed for such equipment.

In estimating the required coverage for units under construction (i.e., placed in service 1974-78), EPA first segmented this capacity into that which had been designed for (1) open-cycle, once-through, and (2) closed-cycle cooling.

All steam electric generating units which were designed for once-through cooling were assumed to require conversion prior to the Section 316(a) exemption while only those units which were assessed to impose a high environmental risk were required to meet the thermal guidelines after this process. These coverage estimates were: 50 percent of nuclear and 31 percent of non-nuclear capacity before Section 316(a) exemptions, and 27.7 percent of nuclear and 10.6 percent of non-nuclear capacity after Section 316(a) exemptions.

In addition to these conversions from open- to closed-cycle, the remainder of steam electric generating units now under construction are planning to install closed-cycle cooling systems. As previously stated, some proportion of these units may be doing so in anticipation of the Act's final guidelines - and therefore, should be included in an assessment of the Act's economic and financial impact. Likewise, those units which are installing closed-cycle cooling for economic reasons should be evaluated but should not be included in measuring the overall impact of the Act. EPA has estimated that the remaining 50 percent of nuclear and 49 percent of non-nuclear capacity to be placed in service 1974-78 are planning to install closed-cycle cooling. Of these, EPA estimated that one-half were doing so for environmental reasons and the other one-half for economic reasons. Since all of these units are designed for closed-cycle cooling, EPA further assumed that none would have adequate time or economic justification to convert to open-cycle cooling if they were eligible for Section 316(a) exemptions. Exhibits 44 and 45 graphically present these capacity coverage estimates.

NEW SOURCE UNITS

Once again, all steam electric generating units are required to install mechanical draft cooling towers or their equivalent - however, new source units, defined herein as those units placed in service after 1978, are assumed to install closed-cycle cooling for operation at the time the units are placed in service. Of the units to be placed in service after 1978, 100 percent of nuclear and 75 percent of non-nuclear (i.e., 100 percent of fossil steam electric) capacity are assumed to be covered before Section 316(a) exemptions. Coverage after these exemptions is assumed to be 72.3 percent of nuclear and 56.6 percent of non-nuclear generating capacity. In addition, EPA has estimated that 34.5 percent of nuclear and 32.5 percent of non-nuclear capacity would install closed-cycle cooling for economic reasons during the period 1979-90. These capacity coverage estimates are graphically presented in Exhibits 44 and 45.

GENERATION CAPACITY AFFECTED

The total generation capacity which is required to install mechanical draft cooling towers or an equivalent technology as a result of the final thermal guidelines, after consideration of those who do so for economic reasons and those who are expected to receive Section 316(a) exemptions, is summarized in the following table:

GENERATION CAPACITY COVERED
(Millions of KW)

Type of Capacity	1974-83	1984-90	1974-90
Prior to 1974 Retrofitted	12.3	-	12.3
1974-78 Retrofitted	23.5	-	23.5
Subtotal	35.8		35.8
1974-78 Planned	34.4	-	34.4
1979-90 New Source	60.7	124.5	185.2
Subtotal	95.1	124.5	219.6
Total	130.9	124.5	255.4

Thus, 130.9 million kilowatts of generation capacity will be required by 1983 to install closed-cycle cooling as a result of the Act - approximately 18 percent of the generation capacity in service at that time. Of this amount, only 35.8 million kilowatts will have been retrofitted from open- to closed-cycle. This amounts to 6.5 percent of the generation capacity in service at the end of 1978 when new source standards are assumed to be applied and 5.0 percent of capacity in service at the end of 1983 when the retrofitting must be completed. In addition, only those units under construction which have been designed for closed-cycle cooling in anticipation of the Act will install these cooling facilities by 1980 - less than 6 percent of the capacity in service in 1980.

The vast majority of the generation capacity placed into service by 1990 which is covered by the Act must install closed-cycle cooling at startup. In addition to the capacity placed in service prior to 1979, 60.7 million kilowatts of the capacity brought on stream during the period 1979-83 and 124.5 million kilowatts placed in service during the 1984-90 period will be covered by new source requirements.

In total, 255.4 million kilowatts of generating capacity will be covered by the guidelines in 1990, excluding those who install closed-cycle cooling for economic reasons and those who are expected to receive Section 316(a) exemptions. Those covered by the guidelines will represent 24.0 percent of all generation capacity by 1990.

The installation of closed-cycle cooling facilities will require the construction of additional generating capacity to operate the cooling towers and to compensate for the loss of efficiency resulting from an increase in turbine back-pressure. This capacity loss, based upon a 1 percent loss for operation of the cooling units and an additional 2 percent due to increased back-pressure, will approximate 4 million kilowatts by 1983, with an additional 3.7 million kilowatts by 1990.

THERMAL INSTALLATION SCHEDULES

The final effluent guidelines as published in the *Federal Register (39 FR 36186)* specify that all units which require conversion from open- to closed-cycle cooling must do so prior to 1 July 1981 unless it can be demonstrated that such conversions would seriously impact system reliability. If system performance would be adversely affected, EPA Regional Administrators or equivalent State Authorities can accept an alternative schedule of compliance providing that the alternative schedule requires units representing at least 50 percent of the affected generating capacity meet the compliance date, that units representing at least 80 percent comply by 1 July 1982, and the remaining units comply by 1 July 1983.

In assessing the economic and financial impact of the thermal guidelines, EPA specified an installation schedule which applied the following rules of thumb for retrofitted units:

- units of 500 megawatts or greater converted for operation of closed-cycle cooling beginning in 1981,
- units of 300 megawatts but less than 500 megawatts converted for operation in 1982, and
- all other units converted for operation in 1983.

Exhibit 46 summarizes the timing implications of these rules.

New source units and those under construction designed for closed-cycle cooling were assumed to have the cooling system operational at the time that the generating unit was placed in service.

IMPACT OF THERMAL GUIDELINES

In assessing the economic impact of the final thermal guidelines, TBS first projected separately the industry conditions which were associated with pollution control equipment installed:

- for economic reasons only,
- before consideration of Section 316(a) exemptions, and
- after consideration of Section 316(a) exemptions.

Having projected these alternatives to the baseline conditions (which excluded any consideration of pollution control associated with the Act), the implications of the Act can be determined by computing on a selective basis the incremental difference between alternatives.

Exhibits 47 to 49 provide summary data for these three sets of operating conditions for selected years.

In addition to the summary statistics which were specified in the previous chapter, Exhibits 47 to 49 provide additional data which:

- detail the replacement capacity required to compensate for the operating requirements and efficiency losses associated with the installation of mechanical draft cooling towers, and
- compute the added energy requirements to operate the cooling towers, to compensate for the turbine back-pressure and to operate less-efficient generating capacity during the period in which capacity being retrofitted is out of service.

The following discussion of the economic impact has been segmented into that which is imputed to the installation of closed-cycle cooling for economic reasons and that which is associated with the Act both before and after Section 316(a) exemptions.

ECONOMIC REASONS

The economic and financial impact associated with the installation of closed-cycle cooling for reasons other than environmental requirements - that is, for economic reasons - can be imputed by computing the difference between the projections (1) with thermal equipment for economic reasons, and (2) for industry baseline conditions. Exhibits 50 to 52 provide detailed information on the impact of closed-cycle cooling for economic reasons for selected years.

Perhaps the most important impacts are those associated with capital expenditures and operations and maintenance expenses, for it is these items which determine the financing requirements, operating revenues and, ultimately, consumer charges.

In computing the economic impact as measured by capital expenditures in a given period, care must be taken to isolate the impact associated with equipment placed in service during the period from the impact of changes in construction work in progress (CWIP). These latter expenditures - if the impact is an increase in CWIP - rightfully should be allocated to the future period in which the equipment is placed into service and, therefore, becomes part of the rate base.[4]

For example, the impact of those who are installing closed-cycle cooling for economic reasons upon capital expenditures during the next decade (1974-83) will be $1.4 billion - that is, an increase in capital expenditures of $0.5 billion. This latter quantity represents progress payments for cooling towers and related replacement capacity which will be installed in the period 1984-90.

The following brief table summarizes the economic impact of closed-cycle cooling for reasons other than environmental as measured by (1) capital expenditures adjusted for changes in construction work in progress, and (2) operations and maintenance (O/M) expenditures:

---

[4] *This adjustment to capital expenditures - while not done in the summary data exhibits - will be explicitly included in the tables referenced throughout the text.*

ECONOMIC IMPACT OF PCE[5] FOR ECONOMIC REASONS
(1974 Dollars)

	1974-77	1974-83	1984-90
Capital Expenditures in billions	$0.4	$1.4	$2.0
O/M Expenses in billions	0.1	0.7	1.7

These capital and operating expenditures led to the following financial implications:

FINANCIAL IMPLICATIONS OF PCE FOR ECONOMIC REASONS
(1974 Dollars)

	1974-77	1974-83	1984-90
External Financing in billions	$0.5	$1.5	$1.4
Consumer Charges in mills/KWH at end of period	0.1	0.1	0.2

These requirements, in terms of both capital market requirements and added charges to consumers for electricity, should be considered in relation to the respective figures for the baseline conditions. For example, the external financing required during the next decade to finance the closed-cycle cooling being planned for economic reasons is $1.5 billion - or stated another way, an increase in industry financing needs by 1.2 percent. In addition, the increase in operating expenses and capital charges which are related to closed-cycle cooling for reasons other than environmental affect the consumer in the form of higher average charges per kilowatt-hour. By 1983, the pass-through of expenses in the form of higher rates will amount to 0.1 mills per kilowatt-hour, an increase of less than 0.5 percent.

---

[5] *PCE will be used in tables throughout the text as an abbreviation for Pollution Control Equipment.*

Thus, the above-mentioned economic and financial implications can be viewed in relative terms as follows:

RELATIVE IMPACT OF PCE FOR ECONOMIC REASONS
(Percent of Baseline Conditions

	1974-77	1974-83	1984-90
Capital Expenditures	0.7%	0.8%	0.9%
O/M Expenses	0.1	0.2	0.5
External Financing	1.4	1.2	1.0
Consumer Charges at end of period	0.4	0.4	0.9

The overall impact of installing closed-cycle cooling for economic reasons - while rather significant in absolute dollars - is relatively small when viewed in the perspective of the total industry levels. Both capital expenditures and external financing (as a percent of the baseline projections) increase slightly. Operating expenses, on the other hand, steadily increase as more and more cooling towers are added. These increases lead to an increase in the relative impact upon consumer charges.

BEFORE 316(A) EXEMPTIONS

In order to evaluate the economic and financial implications associated with the Act before consideration of exemptions based upon Section 316(a) of the Act, TBS computed the difference between the projections which covered (1) all generating units which required closed-cycle cooling (including those who were installing such equipment for economic reasons) before consideration of 316(a) exemptions, and (2) all generating units which would install closed-cycle cooling for economic reasons. Exhibits 53 to 55 provide detailed information on the impact of the Act before 316(a) exemptions for selected years.

The following brief table summarizes the economic impact associated with these conditions:

ECONOMIC IMPACT OF PCE BEFORE 316(a) EXEMPTIONS

(1974 Dollars)

	1974-77	1974-83	1984-90
Capital Expenditures in billions	$0.3	$5.2	$3.2
O/M Expenses in billions	0.1	1.5	3.6

Capital expenditures associated with the Act - even before consideration of possible exemptions - will have little impact in the near term as expenditures prior to 1978 will amount to only $0.3 billion. These expenditures represent the outlays made by utilities who were assumed to have planned closed-cycle cooling in anticipation of the Act and who would not have otherwise installed closed-cycle facilities for in-service operation during the period. The major segment of the expenditures in the next decade will occur after 1980 during the period in which all modifications from open- to closed-cycle cooling will occur. As more and more cooling towers are installed, the costs of operating this equipment increases. Thus, the expenditures for O/M exceed those for capital equipment in the post-1983 period. In total, the final thermal guidelines before 316(a) exemptions will require capital expenditures of $8.4 billion and increase O/M expenses by $5.1 billion by 1990.

These expenditures are expected to have the following effect upon external financing requirements and average consumer charges:

FINANCIAL IMPLICATIONS OF PCE BEFORE 316(a) EXEMPTIONS
(1974 Dollars)

	1974-77	1974-83	1984-90
External Financing in billions	$1.3	$4.8	$2.0
Consumer Charges in mills/KWH at end of period	-	0.4	0.3

The requirement for retrofitting open-cycle systems during the early 1980s has an earlier impact in the form of progress payments for construction work in progress. Thus, while expenditures for equipment placed in service prior to 1978 amounted to only $0.3 billion, the additional financing needs reflected in the build-up in construction work in progress which amounted to $1.2 billion by the end of 1977. In the short run, the consumer charges will be unchanged. In the long run, financing requirements will total $6.8 billion by 1990 with a 0.3 mill/kilowatt-hour increase in average consumer charges.

These economic and financial implications can be placed in terms relative to industry baseline conditions as follows:

RELATIVE IMPACT OF PCE BEFORE 316(a) EXEMPTIONS
(Percent of Baseline Conditions)[6]

	1974-77	1974-83	1984-90
Capital Expenditures	0.6%	2.9%	1.5%
O/M Expenses	0.1	0.5	1.2
External Financing	3.6	3.8	1.4
Consumer Charges at end of period	-	1.7	1.3

The impact of the Act before consideration of 316(a) exemptions is expected to result in a long-term increase in all of the above statistics ranging from 1.2 to 1.5 percent with the most pronounced effect upon capital expenditures. The most significant impact is that which occurs in the early 1980s when all of the conversions from open- to closed-cycle are scheduled. During this period, capital expenditures are expected to be increased by nearly 3 percent while external financing remains near 4 percent throughout the next decade. The average consumer charge per kilowatt-hour should increase by approximately 1.7 percent by 1983.

While these economic impacts are directly associated with the Act, they should not be considered the relevant effects since they do not take into consideration the possible exemptions available to utilities who successfully petition under Section 316(a) of the Act. The economic impact as summarized above should serve as a reference point - that is, the upper bound - of possible economic consequences directly associated with the Act.[7]

---

[6] *Relative comparisons throughout the text will utilize baseline conditions as the relevant denominator rather than including pollution control equipment for economic reasons.*

AFTER 316(A) EXEMPTIONS

The economic and financial implications associated with the Act after consideration of those utilities which are planning to install closed-cycle cooling systems for economic reasons and those which successfully apply for exemptions under Section 316(a) of the Act can be easily obtained by computing the difference between the summary in Exhibit 49 (After 316(a) Exemptions) and Exhibit 47 (For Economic Reasons). Exhibits 56 to 58 provide detailed information on the impact of the Act after 316(a) exemptions for selected years.

The following brief table provides a summary of the economic impact which is associated with the coverage after consideration of both economic reasons and 316(a) exemptions. This impact represents the most likely implications of the thermal guidelines.

ECONOMIC IMPACT OF PCE AFTER 316(a) EXEMPTIONS
(1974 Dollars)

	1974-77	1974-83	1984-90
Capital Expenditures in billions	$0.3	$2.7	$1.8
O/M Expenses in billions	0.1	0.9	2.1

---

[7] *In addition to these direct impacts, existing generating units which were initially exempt by the Act could be required to install closed-cycle cooling to meet State Water Quality Standards. The magnitude of this indirect effect is computed in Chapter V.*

Thus, the best estimate of the capital expenditures required by the final thermal guidelines is $2.7 billion during the next decade with another $1.8 billion required by 1990. Coverage after 316(a) exemptions includes only those generating units which were assessed to have high environmental risk.[8] The expenditures associated with these coverage levels are projected to be slightly more than one-half of those required prior to the 316(a) exemption process. The increase in operating expenses associated with the Act is estimated to be less than $1 billion during the next decade and to increase to $3 billion by 1990.

The following brief table assigns the above-mentioned capital expenditures to the types of capacity segmented by time in service and cooling equipment originally installed:

CAPITAL EXPENDITURES
(Billions of 1974 Dollars)

Type of Capacity	1974-77	1974-83	1984-90
Prior to 1974:			
Retrofitted	-	$ 0.43	-
1974-78:			
Retrofitted	-	0.91	-
Sub-total	-	$ 1.34	-
1974-78:			
Planned	$ 0.33	$ 0.40	-
1979-90:			
New Source	-	0.94	$ 1.85
Sub-total	$ 0.33	$ 1.34	$ 1.85
Total	$ 0.33	$ 2.68	$ 1.85

---

[8] *The methodology which produced these environmental risk assessments was made by ERCO and is summarized in Chapter VI.*

This allocation of capital expenditures is important since it isolates those expenditures which are required to cover the high risk units as defined by the final guidelines and which were placed in service prior to 1974. The coverage of existing units is the major differentiation among the final guidelines, the original proposed guidelines, and other alternatives considered by EPA.

Of the $2.7 billion required for capital expenditures during the next decade, one-half is earmarked for conversion of open-cycle systems to a closed-cycle technology and one-half is related both to capacity which is under construction and planning to install closed-cycle cooling in anticipation of the final guidelines and to new source capacity scheduled for in service operation after 1978. In addition, less than one-third of the capital expenditures needed for retrofitting open-cycle systems will be spent on existing generating units.

Another important aspect of these capital expenditures is their time schedule. As can be seen in the above table, only $0.3 billion will be required prior to 1978 and all of these expenditures are related to utilities who have planned to install closed-cycle cooling on units which are now under construction. Thus, the final thermal guidelines have included a level of coverage and an installation schedule which minimizes the short-term implications of the Act.

These expenditures are projected to require the following external financing and increases in average consumer charges:

FINANCIAL IMPLICATIONS OF PCE AFTER 316(a) EXEMPTIONS
(1974 Dollars)

	1974-77	1974-83	1984-90
External Financing in billions	$0.8	$2.5	$1.2
Consumer Charges in mills/KWH at end of period	-	0.2	0.2

The above-mentioned capital expenditures, combined with the assumed industry operating and regulatory policies, require external financing of less than $1 billion in the near term, and a total of $2.5 billion during the next decade. The related increase in consumer charges is projected to be negligible in the short run and is limited in the long run to 0.2 mill per kilowatt-hour.

The following table summarizes the relative impact of the final guidelines after 316(a) exemptions:

RELATIVE IMPACT OF PCE AFTER 316(a) EXEMPTIONS
(Percent of Baseline Conditions)

	1974-77	1974-83	1984-90
Capital Expenditures	0.6%	1.5%	0.8%
O/M Expenses	0.1	0.3	0.7
External Financing	2.2	2.0	0.8
Consumer Charges at end of period	-	0.8	0.9

In the short run, the major need is for external financing, primarily to finance the construction work in progress at the end of 1977. These requirements increase the total financing needs of the industry by slightly more than 2 percent. All other short-term impacts are projected to be less than 0.5 percent.

The needs in the early 1980s increase the capital expenditures during the next decade by 1.5 percent which, when combined with the O/M expenses, contribute to an increase in average consumer charges of less than 1 percent. In the long run, no impact exceeds 1 percent of the anticipated baseline conditions.

A full evaluation of the Act's economic impact requires that both the thermal and chemical guidelines be computed. However, this evaluation of the thermal guidelines - when placed in the perspective of total industry needs - appears to place minimal constraints upon the industry. This preliminary conclusion is further strengthened when one considers these requirements in the context of the moderation in demand growth detailed in the previous chapter. For example, the final thermal guidelines require nearly $2.7 billion in capital expenditures during the next decade. The reduction in capital expenditures resulting from the moderation in demand growth is projected to exceed $28 billion (after adjustment for changes in construction work in progress). Thus, the final thermal guidelines when combined with the moderate growth assumptions now anticipated by most industry spokesmen require capital expenditures, external financing, etc. which are substantially below those which were being projected less than one year ago. Final conclusions should not be made, however, without a thorough analysis of the chemical guidelines.

CHEMICAL CAPITAL AND OPERATING COST FACTORS

In addition to the above-mentioned thermal guidelines, the Act specifies chemical effluent limitations which range from pH level, to suspended solids, to oil and greases, to metals in waste streams, to chlorine. These final chemical requirements as stipulated by EPA differ somewhat in concept from the above-mentioned specifications of thermal guidelines in that initial limitations are required by 1977 with additional, more stringent, requirements by 1983.

The capital and operating cost factors estimated by EPA to meet both 1977 and 1983 guidelines are detailed in Exhibits 59 to 62. The expenditures have been segmented by type of capacity (nuclear and non-nuclear), year in service (prior to 1974, 1974-78, 1979-90), time of requirements (1977 and 1983 guidelines), and type of expenditure (capital and operating).

A comparison of expenditure levels would suggest that thermal guidelines have a much more significant impact than the chemical guidelines. For example, the 1983 capital cost for mechanical draft cooling towers for non-nuclear capacity ranges from $8.79 to $36.71 per kilowatt - depending upon the original design of the cooling system. In addition to this investment, replacement capacity must be purchased and operated due to the reduction in efficiency. The annual operating cost, again for non-nuclear capacity in 1983, would be $3.19. These impacts per kilowatt compare to chemical capital expenditures which range from $2.93 for new source capacity to $4.09 for existing capacity and annual operating expenditures ranging from $0.43 to $1.02, respectively. This conclusion, however, should be tempered by the fact that the chemical guidelines impact significantly more generating capacity than the thermal guidelines.

CHEMICAL CAPACITY COVERAGE ESTIMATES

EPA has assumed that all steam electric generating capacity will be required to meet the chemical standards. In the case of non-nuclear capacity, this implies coverage levels less than 100 percent - that is, equal to the proportion of non-nuclear capacity which is fossil-fueled steam electric. In addition, no basis for exemptions from these requirements have been formulated.

Thus, the final chemical guidelines will apply to nearly 650 million kilowatts of generating capacity by 1983 and will include an additional 295 million kilowatts brought on stream between 1984 and 1990. The coverage levels required by the thermal guidelines after 316(a) exemptions are projected to be 130 million kilowatts by 1983 and approximately 255 million kilowatts by 1990. Thus, the levels of coverage specified by the chemical guidelines are five times greater than those associated with the thermal guidelines over the next decade; and nearly four times greater in the long run.

CHEMICAL INSTALLATION SCHEDULES

In assessing the economic and financial impact of the chemical guidelines, EPA specified separate installation schedules to meet the 1977 and the 1983 effluent limitation requirements. The installation schedule for the 1977 guidelines was assumed to be based upon the capacity placed in service prior to 1978. This schedule is:

● 1974	15 percent of 1977 capacity
● 1975	20 percent of 1977 capacity
● 1976	25 percent of 1977 capacity
● 1977	40 percent of 1977 capacity

Capacity placed into service in 1978 is assumed to meet these requirements upon placement in service.

In addition to the above schedule, EPA specified an installation schedule to meet the 1983 guidelines which required (1) all capacity placed into service after 1978 to meet the standards at the time of initial operation, and (2) all earlier generation capacity to meet the standards according to the following time schedule:

• 1979	10 percent of 1978 capacity
• 1980	10 percent of 1978 capacity
• 1981	20 percent of 1978 capacity
• 1982	20 percent of 1978 capacity
• 1983	40 percent of 1978 capacity

IMPACT OF CHEMICAL GUIDELINES

The economic and financial implications of the chemical guidelines can easily be obtained by computing the difference between those projections with chemical pollution control (Exhibit 63) and those which represent the baseline conditions for the industry. Exhibits 64 to 66 provide detailed information on the impact for selected years.

The following brief table provides a summary of the most likely impact of the chemical guidelines:

ECONOMIC IMPACT OF PCE FOR CHEMICAL
(1974 Dollars)

	1974-77	1974-83	1984-90
Capital Expenditures in billions	$0.7	$1.3	$0.5
O/M Expenses in billions	0.5	2.1	2.4

Thus, the best estimate of the capital expenditures required by the final chemical guidelines is $1.3 billion during the next decade with another $0.5 billion required by 1990. In addition, the chemical guidelines have a relatively large requirement for capital expenditures in the short run to meet the 1977 guidelines. In the long run, the operating and maintenance expenses associated with chemical pollution control far exceed the capital expenditures. By 1990 the O/M expenses represent two and one-half times the expenditures for capital equipment ($4.5 vs. $1.8 billion).

These expenditures are projected to require the following external financing and added consumer charges:

FINANCIAL IMPLICATIONS OF PCE FOR CHEMICAL
(1974 Dollars)

	1974-77	1974-83	1984-90
External Financing in billions	$0.9	$1.4	$(0.3)
Consumer Charges in mills/KWH at end of period	0.2	0.2	0.1

Once again, the 1977 guidelines impose a relatively high short-term need for external financing. These needs peak in 1983 and actually decline in the late 1980s as the funds internally generated more than compensate for the new source capital requirements. This results from retained earnings, depreciation writeoffs, and tax deferrals flowing from earlier investments. While the short-term impact upon the average cost of electricity is 0.2 mill per kilowatt-hour, this impact declines to 0.1 mill by 1990.

The following table places these effects in perspective by comparing them to the baseline conditions:

RELATIVE IMPACT OF PCE FOR CHEMICAL
(Percent of Baseline Conditions)

	1974-77	1974-83	1984-90
Capital Expenditures	1.3%	0.7%	0.2%
O/M Expenses	0.5	0.7	0.8
External Financing	2.5	1.1	(0.2)
Consumer Charges at end of period	0.8	0.8	0.4

In the short run, capital expenditures and related financing requirements dominate - up 1.3 and 2.5 percent, respectively. These impacts subside by the 1980s and, along with this decline, consumer charges fall off as O/M expenses remain relatively constant as a percent of total operating and maintenance expenses. Thus, the chemical guidelines represent a short-term impact which exceeds that of the thermal guidelines and a relatively insignificant long-term impact.

TOTAL IMPACT OF FINAL GUIDELINES

Having separately computed the effect of thermal and chemical guidelines, one can project the total impact of the final guidelines by summing each of the most-likely estimates previously discussed within this chapter.[9] Exhibits 67 to 69 detail the individual impacts for selected years. The following summary discusses each indicator separately - concentrating upon the total effect, its relative composition, and the timing of the impact.

CAPITAL EXPENDITURES

The following brief table provides a summary of the capital expenditures required to comply with the final guidelines after consideration of exemptions under Section 316(a) of the Act. These levels of investment represent the most likely set of circumstances projected to occur.

CAPITAL EXPENDITURES
(Billions of 1974 Dollars)

	1974-77	1974-83	1984-90
Thermal Guidelines	$0.3	$2.7	$1.8
Chemical Guidelines	0.7	1.3	0.5
Total	$1.0	$4.0	$2.3
Baseline Conditions	$53.4	$179.0	$219.8

---

[9] *This method of obtaining the total impact understates by an insignificant amount the total since it ignores the chemical expenditures required for the replacement capacity constructed to offset the capacity penalty associated with operating mechanical draft cooling towers.*

Thus, the electric utility industry is expected to require $4.0 billion in capital expenditures during the next decade to meet the standards required by the Federal Water Pollution Control Act. These expenditures are concentrated in the early 1980s as all generating units requiring conversion from open- to closed-cycle cooling are being retrofitted and all plants are required to comply with the 1983 chemical guidelines.

While only one-third of the expenditures required during the next decade are related to chemical standards, nearly 70 percent of the short-term requirements are linked to the chemical guidelines. The EPA decision to delay the compliance date for conversion to closed-cycle cooling eased the short-term capital requirements by distributing the investment needs over a longer period of time. The total impact through 1990 amounts to $6.3 billion.

In relative terms, these expenditures have a minor impact on total industry needs as the following table indicates:

CAPITAL EXPENDITURES
(Percent of Baseline Conditions)

	1974-77	1974-83	1984-90
Thermal Guidelines	0.6%	1.5%	0.8%
Chemical Guidelines	1.3	0.7	0.2
Total	1.9%	2.2%	1.0%

During the next decade, the final regulations will require approximately a 2 percent increase in capital expenditures by the electric utilities. The long-run impact amounts to only 1 percent.

These requirements, while amounting to a significant number of dollars, are relatively small when compared with the total needs of the industry. In addition, the magnitude of these expenditures pales when compared to the possible savings available from energy conservation. As detailed in the previous chapter, a moderate reduction in growth from the historic rates would free up more than $28 billion in investment funds during the next decade - and a staggering $91 billion by 1990. If the electric industry could have met the capital requirements projected prior to last winter, they should not have trouble meeting the added requirements to comply with the Act.

The above statement is clearly an oversimplification since the industry is currently in dire financial straits (see Chapter I). But such a statement highlights the fact that the plight of the electric utility industry is not intimately tied to the environmental movement. Rather, the problems of the industry evolve from other conditions within the industry which, if corrected, could provide a sufficiently healthy climate for the above-mentioned capital requirements to be met. The decision of EPA to delay the major expenditures until the 1980s should ease the short-term capital crunch and provide the industry an adequate period to correct the underlying problems.

O/M EXPENSES

The following brief table provides a summary of the operating and maintenance expenses required to comply with the Act:

O/M EXPENSES

(Billions of 1974 Dollars)

	1974-77	1974-83	1984-90
Thermal Guidelines	$0.1	$0.9	$2.1
Chemical Guidelines	0.5	2.1	2.4
Total	$0.6	$3.0	$4.5
Baseline Condition	$92.0	$292.5	$311.2

Thus, the electric utility industry is expected to spend an additional $3.0 billion on operations and maintenance during the next decade - and a total of $7.5 billion by 1990.

Whereas the thermal guidelines represented approximately two-thirds of the capital requirements during the next decade, the chemical guidelines represent more than two-thirds of the O/M expenses during the same period.

Once again, these expenses are relatively small in terms of industry totals as the following table demonstrates:

O/M EXPENSES
(Percent of Baseline Conditions)

	1974-77	1974-83	1984-90
Thermal Guidelines	0.1%	0.3%	0.7%
Chemical Guidelines	0.5	0.7	0.8
Total[10]	0.7%	1.0%	1.4%

During the next decade, the final regulations will increase O/M expenses by 1 percent with the long-run impact gradually increasing to 1.4 percent as a result of the cumulative effect of adding pollution control equipment. It should be remembered that O/M expenses related to the Act should - on a relative basis - gradually increase over time as the percentage of generating units covered by the Act increases.

In addition to the economic impact associated with increased expenditures, the final thermal guidelines impose an energy impact which can be expressed in terms of (1) an increase in fuel consumption, and (2) an increase in the balance of trade to the extent that the additional fuel requirements are met by importation of petroleum products.

Based upon the capacity penalty and period of outage discussed earlier in this chapter, TBS estimates that the fuel penalty after consideration of 316(a) exemptions will be equivalent to approximately 9 million tons of coal by 1983. Assuming the fuel mix of 80 percent coal and

---

[10] *Totals may not equal sum of parts due to rounding.*

20 percent oil, the final guidelines would increase the national demand for coal by less than 1 percent and the demand for oil by less than 0.1 percent in 1983.

The added demand for petroleum products amounts to approximately 18,000 barrels per day by 1983. The total balance of payments cost of the final guidelines will depend upon the price of oil and the proportion of increased demand which will be met by importation. If one were to take the worst case assumptions - $12 per barrel for oil and 100 percent imported - the annual balance of payments effect after 316(a) exemptions would be a maximum of $80 million in constant 1974 dollars by 1983.

EXTERNAL FINANCING

The following brief table summarizes the external financing requirements of the industry which are associated with the Act:

EXTERNAL FINANCING
(Billions of 1974 Dollars)

	1974-77	1974-83	1984-90
Thermal Guidelines	$0.8	$2.5	$1.2
Chemical Guidelines	0.9	1.4	(0.3)
Total	$1.7	$3.9	$0.9
Baseline Conditions	$35.8	$126.3	$146.3

The incremental increase in external financing needs during the next decade nearly equals the capital expenditures level of $4.0 billion. External financing requirements in the short run exceed the capital expenditures (adjusted for changes in construction work in progress) - reflecting the financing needs for the added construction work in progress. The long-run needs fall off as the incremental sources of internal funds begin to compensate for the added pollution control requirements.

On a relative basis the most significant effect in the short run and extending throughout the next decade is a relative need for external financing.

EXTERNAL FINANCING
(Percentage of Baseline)

	1974-77	1974-83	1984-90
Thermal Guidelines	2.2%	2.0%	0.8%
Chemical Guidelines	2.5	1.1	(0.2)
Total	4.7%	3.1%	0.6%

The above table indicates that the short-term addition to external financing by the electric utility industry is nearly 5 percent, moderating to 3 percent by 1983 and dropping off to less than 1 percent by 1990.

While these requirements may increase the financing burden of the industry, they represent less than 20 percent of the capital freed up as a direct result of energy conservation.

CONSUMER CHARGES

The ultimate impact of the guidelines is reflected in the average cost of electricity to the consumer. As the following table shows, the overall impact of the final guidelines on the average cost per kilowatt-hour is less than 0.5 mill throughout the period under consideration:

CONSUMER CHARGES
(Mills/KWH in 1974 Dollars)

	1977	1983	1990
Thermal Guidelines	-	0.2	0.2
Chemical Guidelines	0.2	0.2	0.1
Total	0.2	0.4	0.3
Baseline Conditions	24.0	23.6	22.4

When these increases are placed in the context of the baseline conditions, the overall impact on the cost of electricity peaks at a 1.7 percent increase in 1983.

CONSUMER CHARGES
(Percent of Baseline Conditions)

	1977	1983	1990
Thermal Guidelines	-	0.8%	0.9%
Chemical Guidelines	0.8%	0.8	0.4
Total[11]	0.8%	1.7%	1.3%

---

[11] *Totals may not equal sum of parts due to rounding.*

Although the percentage impact of the final guidelines doubles from 1977 to 1983, the absolute level of consumer charges (in constant 1974 dollars) declines from 24.2 to 24.0 mills per kilowatt-hour as the growth in the use of electricity exceeds the growth in required revenues. This decline in the cost of electricity continues through the 1980s and reaches a level of 22.7 mills per kilowatt-hour by 1990.

Thus, while the cost of electricity is expected to increase as a direct result of the Act, the relative price of electricity will - after peaking in the mid-1970s - begin a gradual decline as the industry returns to a moderate rate of growth after a period of rapid escalation in construction costs and fuel prices during the early 1970s.

IV. EVALUATION OF OTHER THERMAL OPTIONS

INTRODUCTION

A number of alternative thermal guidelines were evaluated between 4 March 1974 when the original guidelines were proposed and 8 October 1974 when the final guidelines were published. The options for the thermal guidelines ranged from covering almost all plants placed into service since 1950 at one extreme, to covering only those coming on-line after 1978 at the other.

The options displayed a hierarchy of three primary criteria which were considered in achieving a balance between economic impact and environmental risk:

- age of units was the most significant criterion and affected both economic and environmental results the most;
- size of unit was added to age as a criterion to strike a finer balance between two age cutoffs;
- capacity factor was considered in some options as a tertiary factor to supplement both age and unit size.

Preceding page blank

The selected option, of course, does employ the first two criteria, but does not include capacity factor.

The five options presented in this chapter provide a good perspective of the range of economic impacts which were under review. The environmental impacts for a similar range of options are presented in Chapter VI. These were not necessarily those options given the most serious consideration, but they best display the variations possible in economic impact. The five, in terms of capacity exempted, are:

- Option 1 - exempt all units placed into service before 1979;
- Option 2 - exempt all units placed into service before 1974;
- Option 3 - exempt all units placed into service before 1972;
- Option 4 - exempt all units placed into service before 1961, and all units of less than 200 megawatt capacity; and
- Option 5 - exempt all units placed into service before 1956, and all units of less than 25 megawatt capacity or in systems of less than 150 megawatts, and all units operating at less than 40 percent capacity factor.

In addition, the guidelines proposed in March 1974 - which exempted all small units in plants of 25 megawatts or less and in systems of 150 megawatts or less, and units scheduled for retirement prior to 1990 - were re-evaluated.

THERMAL CAPACITY COVERAGE ESTIMATES

The above-mentioned options differ only in their coverage of capacity which is either existing or under construction. Option 1 exempts all units in these two categories; whereas, the other options limit exemptions to some portion of existing capacity.

Capacity coverage estimates are graphically presented in Exhibits 70 and 71 for the final guidelines, the guidelines proposed in March 1974, and the five options.

IMPACT OF THERMAL OPTIONS

Economic and financial projections are presented in Exhibits 72 to 76 for each of the options after consideration of Section 316(a) exemptions. Exhibit 77 provides comparable data for the proposed guidelines.

The comparative impacts of the options are summarized, item by item, in the following sections. In order to simplify the following analysis, the only time period discussed will be the next decade, 1974-83.

Since all existing capacity required to convert from open- to closed-cycle has been scheduled to do so between 1981 and 1983, this time period captures all of the differences among the options.

While the primary differences among the options result from the variation in coverage levels assumed for existing coverage, the difference between Options 1 and 2 is solely the result of covering units which are being constructed and were designed for open-cycle cooling.

CAPITAL EXPENDITURES

Under the baseline conditions, capital expenditures for plant and equipment placed into service during the next decade are projected to be $179.0 billion in constant 1974 dollars. The five options, after 316(a) exemptions, would increase that amount from $1.4 to $4.3 billion as summarized in the following table:

CAPITAL EXPENDITURES (1974-83)
(Billions of 1974 Dollars)

	Capital Expenditures	Percent of Baseline
Final Guidelines	$2.7	1.5%
Option 1	$1.4	0.8%
Option 2	2.3	1.3
Option 3	2.7	1.5
Option 4	3.9	2.2
Option 5	4.3	2.4
Proposed Guidelines	$5.2	2.9%
Baseline Conditions	$179.0	-

These expenditures compare to $2.7 billion for the final guidelines and $5.2 billion for those proposed in March 1974 - with the final guidelines falling within the mid-range of the five options:

O/M EXPENSES

The following brief table summarizes the operations and maintenance expenses represented by the five thermal options during the next decade:

O/M EXPENSES (1974-83)
(Billions of 1974 Dollars)

	O/M Expenses	Percent of Baseline
Final Guidelines	$0.9	0.3%
Option 1	$0.7	0.2%
Option 2	0.8	0.3
Option 3	0.9	0.3
Option 4	1.1	0.4
Option 5	1.1	0.4
Proposed Guidelines	$1.3	0.4%
Baseline Conditions	$292.5	-

The O/M expenses range from $0.7 to $1.1 billion in constant 1974 dollars and in all cases amount to less than 0.5 percent of the baseline.

EXTERNAL FINANCING

The financing requirements during the next decade cover the plant and equipment placed in service during the next period plus the construction work in progress at the end of the period for in-service operation after 1983. Thus, external financing for the next ten years can be, and generally is, higher than capital expenditures after the latter has been adjusted for the change in construction work in progress. In general, external financing represents slightly more than 60 percent of all financial requirements - with the remainder being internally generated funds.

The table that follows summarizes the external financing for the five options as well as both the final and proposed guidelines:

EXTERNAL FINANCING (1974-83)
(Billions of 1974 Dollars)

	External Financing	Percent of Baseline
Final Guidelines	$2.5	2.0%
Option 1	$1.5	1.2%
Option 2	2.2	1.7
Option 3	2.5	2.0
Option 4	4.0	3.2
Option 5	4.6	3.6
Proposed Guidelines	$5.9	4.7%
Baseline Conditions	$126.3	-

CONSUMER CHARGES

The impact on the consumer of these alternative levels for thermal coverage will be the following increase in the average cost of a kilowatt-hour of electricity in 1983:

CONSUMER CHARGES (1983)
(Mills/KWH; 1974 Dollars)

	Consumer Charges	Percent of Baseline
Final Guidelines	0.2	0.8%
Option 1	0.1	0.4%
Option 2	0.2	0.8
Option 3	0.2	0.8
Option 4	0.3	1.3
Option 5	0.3	1.3
Proposed Guidelines	0.4	1.7%
Baseline Conditions	23.6	-

The options range from an increase of 0.1 mill to 0.4 mill per kilowatt-hour and in no option do these increases in consumer charges exceed 2 percent of the projected baseline level of 23.6 mills per kilowatt-hour. The final guidelines are anticipated to increase the cost of electricity to the consumer by 0.2 mills.

SUMMARY

As the preceding discussion has indicated, the total economic impact of the final guidelines falls within the mid-range of those for the five options. In general, the impact of Option 5 is approximately three times as large as the comparable effect of Option 1 during the next decade. The final guidelines' impact is approximately one-half of the impact of the originally proposed guidelines which were published in March 1974.

V. EVALUATION OF STATE WATER QUALITY STANDARDS

INTRODUCTION

The alternatives to the final guidelines which were evaluated in the previous chapter differ only in the assumed coverage levels for existing steam electric generating capacity.[1] In specifying these alternatives, EPA explicitly recognized that existing units which were not covered by the Act still would be required to meet State Water Quality Standards. These units, therefore, could be required to convert from open- to closed-cycle cooling systems in order to meet the state standards. The following analysis - based upon the final guidelines - attempts to estimate the potential impact of State Water Quality Standards. The impact of these standards upon any other option then can be directly estimated by comparison of the coverage levels for existing units.

THERMAL CAPACITY COVERAGE ESTIMATES

The final guidelines exempt all units placed into service before 1970 and all units of less than 500 megawatt capacity placed into operation between 1 January 1970 and 1 January 1974. As a result, the final guidelines' coverage of existing units is limited to only the largest baseload units placed into service after 1 January 1970. EPA estimated that the final regulation covered 45.8 percent of existing nuclear and 4.6 percent of existing non-nuclear capacity prior to any consideration of additional exemptions under Section 316(a) of the Act. The coverage of existing units was reduced to 12.9 percent of nuclear and 2.2 percent of non-nuclear after 316(a) exemptions. Thus, the final guidelines do not in any way cover 54.2 percent of existing nuclear and 95.4 percent of existing non-nuclear capacity.[2] Some proportion of these units may not - and probably do not - meet State Water Quality Standards.

---

[1] *Option 1 also excludes units currently under construction - that is, units to be placed into service 1974-78.*

In assessing what proportion of existing units would not meet the state standards, EPA relied upon the concept of environmental risk developed by Energy Resources Company, Inc. (ERCO) and summarized in Chapter VI. That is, all existing units which were not covered by the Act and which were assessed to pose high environmental risks were assumed to be required to convert from open- to closed-cycle under State Water Quality Standards. This definition of State Water Quality Standards implies that all high risk plants - even those which are not directly covered by the Act -

---

[2] *It should be noted that 17 percent of the non-nuclear capacity is not fossil-fueled steam electric.*

will be required to install closed-cycle cooling systems as a result of either the Act (those covered by the Act) or State Water Quality Standards (those existing units not covered by the Act).

EPA estimated that the coverage by state standards under the final guidelines after consideration of Section 316(a) exemptions would be 1.1 percent for existing nuclear and 20.5 percent for existing non-nuclear capacity. In total, this level of coverage means that 14.0 (that is, 12.9 + 1.1) percent of existing nuclear and 22.7 (that is, 2.2 + 20.5) percent of existing non-nuclear has been assessed as high environmental risk. Exhibits 78 and 79 graphically present these for both the final thermal guidelines and the alternative options outlined in the previous chapter.

IMPACT OF STATE WATER QUALITY STANDARDS

The economic analysis thus far has differentiated the impact of the thermal guidelines from those expenditures for closed-cycle cooling which were installed for economic - not environmental - reasons. In addition to this impact, there exists a potential for additional expenditures to meet the requirements associated with state water standards. This latter category can best be evaluated by comparing the projections (1) after consideration of Section 316(a) exemptions, and (2) after consideration of 316(a) exemptions and State Water Quality Standards. Exhibit 80 provides summary data for the combination of after 316(a) exemptions and after state standards. In addition, Exhibits 81 to 83 provide detailed information on the impact of State Water Quality Standards for selected years.

The following brief table summarizes the economic impact associated with these conditions:

ECONOMIC IMPACT OF STATE WATER QUALITY STANDARDS
(1974 Dollars)

	1974-77	1974-83	1984-90
Capital Expenditures in billions	$0.0	$2.6	$0.0
O/M Expenses in billions	$0.0	$0.4	$1.1

The potential capital expenditures required to retrofit all existing high environmental risk capacity which is not covered by the Act amount to $2.6 billion - nearly equal to the impact of the Act itself. In addition, all of this effect occurs in the early 1980s. The operating and maintenance expenses are less than $0.5 billion in 1983 and continue at a reduced level - accumulating to $1.1 billion by 1990.

These expenditures are projected to require the following external financing and increases in the cost of electricity:

FINANCIAL IMPLICATIONS OF STATE WATER QUALITY STANDARDS

(1974 Dollars)

	1974-77	1974-83	1984-90
External Financing in billions	$0.0	$3.4	$(1.6)
Consumer Charges in mills/KWH at end of period	0.0	0.2	0.1

Thus, State Water Quality Standards are projected to increase the need for external financing by $1.8 billion - all in the early 1980s. These funds are needed to finance the capital requirements and the short-term increase in construction work in progress. The impact upon consumer charges is 0.2 mill in 1983 with a decline to 0.1 mill by 1990.

VI. ENVIRONMENTAL IMPACT OF THE THERMAL GUIDELINES

INTRODUCTION

The evaluation of environmental impacts upon water bodies has been integral to the process of establishing appropriate thermal effluent guidelines for the steam electric utility industry. This chapter presents in three sections: (1) the technology of thermal pollution, including the alternative techniques of alleviating it; (2) the factors that influence environmental impact, especially the utility plant characteristics which bear on the degree of that impact; and (3) the environmental evaluation of the guideline options considered by EPA.

TECHNOLOGY OF THERMAL POLLUTION

Any power plant that generates power from heat (either from burning fossil fuel or fissioning uranium) must have a place to reject heat. According to the second law of thermodynamics it is impossible to change all the heat into electricity with no waste. In the case of gas turbines, the combustion products are exhausted directly into the atmosphere at about 1,000°F.

In the case of steam turbines, the cost of boiler water and the low pressure of steam at ambient temperature make it impractical and inefficient to exhaust the steam directly into the atmosphere. The steam

---

1. *The material in this chapter summarizes the results of research performed for EPA by Energy Resources Co., Inc. (ERCO).*

Preceding page blank

cooling water cannot be recycled through towers or ponds indefinitely because chemicals collect by leaching and from additives while nearly pure water is slowly lost by evaporation. Some of the water is bled off and replaced by fresh water to avoid overconcentration: the water that is bled off is called *blowdown*. If the water is bled off after passing through the tower or pond, it is called *cold-side blowdown*, as opposed to *hot-side blowdown*, where the water goes directly from the powerplant condensers into the river.

Available technologies for thermal abatement include the operation of:

- Cooling ponds and lagoons
- Spray systems and spray ponds
- Natural draft wet towers
- Mechanical draft wet towers
- Natural and mechanical draft dry towers
- Diffusers

The first four systems cool water primarily by evaporation, while the fifth - dry towers - cools only by exchanging heat between two fluids, hot water and cooler air. The sixth system distributes the waste heat directionally, so that the ecological effects can be minimized by either reducing or increasing mixing as a function of the nature of particular ecosystems.

Each of these systems requires different amounts of energy and water to effect the same amount of cooling. Furthermore, the operation of each of these systems affects the environment differently. This section provides a description of the alternative technologies employed to achieve cooling.

COOLING PONDS AND LAGOONS

Given sufficient land, cooling ponds and lagoons are the cheapest and, environmentally, the most satisfactory method to achieve reductions in thermal loads. The heat is rejected from the pond surface by the natural effects of conduction, convection, radiation, and evaporation. Cooling ponds can be classified as completely mixed, stratified and flow-through ponds. In a completely mixed pond the flow between the inlet and outlet locations of the pond combined with wind mixing tend to keep the pond at a nearly uniform temperature. Stratified ponds are warm on the surface near the outfall and cooler on the bottom near the intake. In a flow-through pond the temperatures decrease continually, along the pond. The pond effluent can either be returned to the plant intake (closed cycle) or discharged to a natural receiving body (open cycle). Flow-through and stratified ponds are more common and more effective than completely mixed ponds.

SPRAY SYSTEMS AND SPRAY PONDS

Spray ponds are available in two different configurations: conventional spray ponds and powered spray systems. In conventional spray ponds, warm water is pumped out of spray nozzles to increase the exposure of surfaces to the atmosphere for cooling. Powered spray systems consist of multiple nozzle assemblies and motors, or a thermal rotor module with numerous disks spinning on a common shaft, and driven by a single motor. Spray systems rely on expanded surface contact to increase evaporation. Spray ponds require little maintenance, but are subject to poor operation due to climatic conditions.

NATURAL DRAFT WET TOWERS

Natural draft wet towers are basically large chimneys which provide a draft to pull air over a large surface of water. Among the advantages of natural draft wet towers are long-term maintenance-free operation, smaller amounts of ground space required for multiple towers, reduced piping costs when towers can be located adjacent to plant, no electricity required for operating fans, fewer electrical controls and less mechanical equipment. On the other hand, it is not possible to control outlet temperatures as well as with mechanical draft towers. Also, because they are usually 500 feet high, natural draft towers tend to dominate the landscape.

MECHANICAL DRAFT WET TOWERS

Mechanical draft evaporative (wet) towers are divided into two categories, forced air flow and induced air flow. Induced draft towers are further subdivided into counterflow and crossflow towers. Crossflow induced draft towers can usually attain better thermal performance than counterflow towers. Mechanical draft towers are much smaller than natural draft, and may be as low as 50 feet in height.

NATURAL AND MECHANICAL DRAFT DRY TOWERS

In natural and mechanical draft dry tower heat rejection systems, the circulating water never comes into direct contact with the cooling air. There are indirect and direct air-cooled condensing systems. The first uses a condenser at the turbine to condense the exhaust steam. The second uses cooling coils in the tower without the use of a condenser or circulating water. The large steam piping required appears to make the direct system infeasible for large power plants.

DIFFUSERS

Outfalls can be designed to distribute the flow of waste heat in streams to achieve desirable ecological goals. In rivers, heated water may be concentrated on the surface to maximize atmospheric cooling and minimize downstream effects, or concentrated in midstream to minimize effects on shore-line biota, or diffused across the width of the river to minimize the temperature effects anywhere in the river. In salinity-stratified estuaries, it may be possible to both withdraw and return the water from middle levels, minimizing effects on both surface and bottom species.

The closed-cycle cooling methods with significant present use are natural and mechanical draft wet towers, ponds, and spray ponds. Many closed-cycle cooling systems have been, and will continue to be, installed by utilities for economic reasons whether or not required to by EPA for environmental reasons. The projections of impact of the EPA regulations throughout this report take that factor into account and state impacts in terms of incremental systems only.

The guidelines provide that both Best Practicable Control Technology (BPCT)[3] and Best Available Technology Economically Achievable (BATEA)[4] to control thermal pollution can be met by one suitable technology: evaporative external cooling to achieve essentially no discharge of heat into waterways except for cold-side blowdown, in a closed, recirculating cooling system.

The mechanical draft evaporative cooling tower has been used as the basis for all analysis of costs and environmental impacts.

---

[3] *Currently available for 1977; in assessing BPCT a balancing test between total cost and effluent reduction benefits is made. In some instances, this test may eliminate the application of technology which is high in cost in comparison to the minimal reduction in pollution which might be achieved.*

[4] *The highest degree of technology that has been demonstrated as capable of being designed for plant operation; costs for this treatment may be much higher than for treatment by "best practicable" technology.*

FACTORS THAT INFLUENCE ENVIRONMENTAL IMPACT

The factors that directly influence the environmental impact of the heated water discharges are: (1) location; (2) amount; (3) temperature; and (4) frequency. The powerplant characteristics which directly affect these parameters are:

- receiving water type (river, lake estuary, ocean)
- cooling method (open cycle, "helper" system, closed cycle)
- safezone
- efficiency
- heat rate
- unit size
- capacity factor
- age

SAMPLE POWERPLANTS STUDIED

In order to gather extensive data which was not publicly available, regarding utility plant characteristics, a random sample of 180 plants or units was selected from the publication *Steam Electric Plant Factors (National Coal Association, January 1974)*. Those 180 plants represent approximately 14 percent of the 1,273 plants listed, and account for 396 steam-electric utility generating units operating in

1974. The sample data was supplemented by a telephone and telegram survey, by a literature search, and by data from *FPC Form 67* computer tapes issued monthly by the Federal Power Commission.

Individual assessments were also made of environmental hazards due to thermal effluent for each of the 180 plants in the sample. Analysis of the plant characteristics and environmental assessments identified the patterns described below. (The sample data has been adjusted to correctly reflect figures such as mix of fossil and nuclear units.) Those patterns eventually formed the basis for the environmental evaluation of each of the options.

RECEIVING WATER TYPE

The damage from thermal pollution depends on the method by which heat enters and leaves a receiving water body:

- On a river, most of the heat is removed downstream by the river flow.
- On a lake, most of the heat is dissipated into the air by conduction and evaporation.
- On an estuary the heat is removed in alternating directions by tidal flows.
- In the open ocean, the heat is removed by natural currents or convection.

About 10 percent of the plants utilize municipal or industrial sewage water, aqueducts, or other combined techniques in which most of the heat is dissipated before entering a navigable waterway. As such, those plants are exempt on the grounds of not using waterways.

The damage from heat clearly depends on the type of receiving water body and on its size. If the water body is large, many animals can avoid the hottest areas and those which are harmed will be rapidly replenished by others nearby. If the body is small enough so that an entire habitat is strongly heated (for example, an entire lake surface or river cross-section), then a few days' damage may take years to reverse.

Approximately 60 percent of steam electric production capacity has been located on rivers over the last 20 years. Approximately another 20 percent has been on lakes. Of the remaining 20 percent, half is located on estuaries, and half utilizes wells, city water, sewage water or other sources for cooling. Ocean water is used by less than 3 percent of all plants.

Most significant in terms of environmental impact are the receiving water types for plants using once-through cooling, as shown in Exhibit 84, since all closed-cycle cooling systems present no environmental hazard.

The current mix of such plants is approximately 50 percent on rivers, 30 percent on lakes, and 15 percent on estuaries. Only 5 percent use water from other sources. Some trends are evident: estuary sites are growing slowly; lake sites are growing rapidly; and river sites are decreasing rapidly. Much of this trend is probably due to the large size of new plants. The Great Lakes and the ocean are large compared to the water needs of any powerplants now contemplated, whereas only the Mississippi and Columbia River basins have much larger flows all year than the largest plants require for plant draft.

COOLING METHOD

Heat may be rejected from the cooling water at three different stages:

- with once-through cooling, the heated water is returned directly to the receiving water body;
- with "helper" systems, all or part of the heated water is partially cooled all or part of the time by a tower, pond or ditch before returning to the receiving water body;
- with true closed-cycle cooling, nearly all the water is cooled by a tower or pond and then recycled through the condenser.

The first method may cause mortality to both organisms drawn through the plant and those near the outfall, while the second greatly reduces damage near the outfall, but may considerably increase damage to those drawn through the plant, and the third generally eliminates thermal damage to the water body; all organisms drawn through the plant are killed but their number is small since the make-up water needs are only a few percent of the water used by either of the other methods.

An indirect but sometimes very important effect on rivers from switching to closed-cycle systems is an increase in the quantity of water consumed by cooling. The effect varies considerably in the different climatic regions but generally in open-cycle systems about half of the heat discharged to a river, or well dispersed in a large lake, results in evaporative heat transfer while the other half transfers to the atmosphere by conduction and convection.

With closed-cycle systems of cooling towers and ponds about three-fourths of the heat transfer results in evaporation, an increase of up to 50 percent over open-cycle. Further, a man-made cooling pond can result in additional water requirements due to enhanced natural evaporation of the impounded water. However, the ability of a pond to store surplus runoff from the wet season for use in the dry season can often completely compensate for added evaporation. Overall, it appears that no more than a 30 percent increase in evaporation water loss could result from a massive increase in closed-cycle cooling.

The industry is rapidly increasing its usage of closed-cycle cooling. In 1970 approximately 78 percent of all steam electric plants relied upon once-through cooling. By 1977, that percentage is expected to decline to 60 percent.

Exhibit 85 is surprising in its indication of the method by which the increase in closed-cycle cooling is being accomplished. Cooling ponds represent approximately 4 percent of the industry; spray ponds and semi-closed systems are much smaller. EPA's initial choice for BATEA (mechanical draft cooling towers) has also been nearly constant at just over 10 percent of the industry for 20 years. Practically all the net increase in closed-cycle cooling is due to the rapid growth in natural draft cooling towers during the 1970s. Probably the decreased energy penalty, land use, fogging, drift, and noise compensate for the larger capital cost of natural draft compared to mechanical draft towers.

SAFEZONES ON RIVERS

A very significant factor in terms of environmental risk is the percentage of a river's total flow which is not affected by a plant's thermal discharge. As a result of consultation with numerous biological scientists employed by universities, by private research organizations, and by government agencies the following designations were developed:

- high risk - less than 30 percent of river flow unaffected
- low risk - over 70 percent of river flow unaffected
- moderate risk or undetermined - 30-70 percent unaffected

The last category, between 30 percent and 70 percent of river flow not affected, it was agreed, constituted a risk which could not be ascertained without a detailed biological demonstration such as that contemplated under Section 316(a).

Exhibit 86 shows that no pronounced change in safezones has been exhibited over the last fifteen years, mainly because relatively few once-through river plants are being built (up only 25 percent in the final decade). Placing larger new units at an old site necessarily reduces the safezone but this is counterbalanced by the increased attention given to locating on sufficiently large rivers and both economic and environmental constraints forcing the largest plants to use closed-cycle cooling.

EFFICIENCY

Until 1960, the efficiency of electrical production had been increasing rapidly over time. Between 1920 and 1960 technologically feasible pressures increased ten-fold to 3,400 psi, temperatures doubled to over 1,000° F, and the average efficiency nearly tripled to 32 percent. Although electrical consumption doubled each decade in this period, the environmental impact was greatly mitigated by the improvements in efficiency.

While the average plant in 1920 rejected 2 units of energy into the air and 6 units into water for each unit converted into electricity, the 1960 rejection rate was 1-1/2 units of energy into water for each unit converted into electricity. As a result, the nearly 16-fold increase in electrical production increased the heat rejected into waterways only about 4-fold; while this heat increase is large, it amounts to less than 2 percent annual growth per capita and is similar to the growth of the whole economy during the period.

Since 1960, however, the improvement in efficiency has been negligible. One unit was built with a maximum pressure of 5,000 psi, temperatures up to 1,200°F, and double reheating providing an efficiency of 40 percent; but reliability was a problem. Most other new fossil units have shown efficiencies of about 36 percent. The common nuclear units have an efficiency of 32 percent and since there are no stack losses, 2 units of energy must be rejected into the cooling water for each unit turned into electricity. Few higher efficiency nuclear units are expected until at least the mid-1980s. Since nuclear units will soon be providing over one-half of the capacity additions, the demand for cooling water will grow about 6 percent per capita, which is faster than the growth of electrical demand.

Return to a pattern of increasing efficiency which can compensate for increased demand is not likely for at least several decades, although combined gas turbine and steam electric systems might approach 45 percent efficiency within ten years. High temperature gas reactors are near 40 percent; breeder reactors, magnetohydrodynamic and electrogasdynamic generators, and fusion reactors are at least decades from becoming a major source of energy. Geothermal generation and solar energy create more waste heat than present generators; their great advantage lies in fossil fuel savings. Fuel cells promise major reductions in waste heat and may be useful for temporary storage, but appear impractical with natural fuels. Nevertheless, all the above are expected to account for less than 5 percent of the new generation added in the next ten years.

HEAT RATE

Heat rate measures the amount of fuel that must be burned to produce one unit of electricity. It is commonly given as British Thermal Units per kilowatt-hour. It has been suggested that units with large heat rates should be exempted from regulation because those units require so much cooling water that they cannot afford to raise their electric rates enough to pay for the cost of cooling towers. However, this argument can easily be turned around. Closing down high heat rate units will give a large reduction in thermal pollution and fuel use with only a small reduction in generating capacity. This criterion has now been bypassed since practically all high heat rate units will be exempted on the basis of age. Nearly all units built since 1960 have heat rates within a 20 percent range, with nuclear units at the top of the range. The heat rates for new plants are conjectural but the major trend is still evident - the heat rate decreased rapidly through the late 1950s and has nearly stablized since then.

UNIT SIZE

As prospective savings from improved efficiency have declined, the utilities have utilized a breakthrough in boiler technology in the 1950s to reap economies of scale. Maximum boiler and generator unit sizes increased 6-fold between 1955 and 1972 to 1,150 megawatts with only a doubling of employees per unit. Although many plants containing several of these large units are now planned, the technology is not without environmental costs since very few streams, lakes, or bays in the United States are large enough to cool these plants without undergoing large temperature rises.

The only direct effect of unit size on thermal pollution is during periods of breakdown and maintenance. When a single-unit plant is shut down for maintenance, all of its thermal effluent ceases. The temperature near the cooling water outfall may drop rapidly by

10^{o} to 20^{o}F. The resulting "cold shock" may be fatal to organisms that have acclimated to the outfall temperatures. If many smaller units are used the temperature changes on shutdown of a single unit are much less.

A number of indirect effects of unit size may be important. The small units tend to be older, more lightly loaded, and less efficient. The administrative costs of monitoring them are much higher and the conversion costs moderately higher for a given reduction in environmental risk. The age exemption has now eliminated practically all units previously being considered for a size exemption.

Exhibit 87 shows the size of the largest units has grown erratically because each large increase required new technological breakthroughs for safe reliable operation. The average unit size has, nonetheless, grown continuously. Therefore, the total number of steam electric units seems likely to remain between 2,000 and 3,000 for the entire second half of the twentieth century.

CAPACITY FACTOR

Environmental risk depends mainly on net generation and heat rate. The capacity factor is the ratio of net generation to generating capacity, so it obviously correlates with the cost/benefit ratio. But capacity factor, size space, and heat rate all correlate well with age.

The main difference in capacity factors is between fossil and nuclear plants. The higher heat rate of nuclear plants, however, cancels out their advantage in high capacity factor.

Capacity factor would cause more problems than almost any other measure as a criterion for exemption. Exemption for all time on the basis of capacity factor in an arbitrary base year in the past would lead to continual challenges from plants that had fallen below the cutoff after the base year. On the other hand, establishing the base year in the future would subject the exemptions to the uncertainties of the future and make exemptions to some degree a matter of management policy for each utility system. Basing exemptions on current production would raise problems of planning multi-year construction on the basis of exemptions which fluctuate yearly.

AGE

Age is a suitable surrogate for many other unit characteristics which affect environmental risk. It correlates very well with efficiency, heat rate, size, and capacity factor. Because efficiency and heat rates have not kept pace with the trend in size, the newer units pose a higher environmental hazard.

Furthermore, the fact that newer units have high capacity factors (as a logical result of their cost/benefit performance) indicates that those units operate a high percentage of the time and thus pose a more prolonged hazard than units used only periodically.

The age distribution projected for all units in operation January 1, 1978, is presented in Exhibit 88. Approximately 52 percent of 1978 capacity is expected to have been placed into service between 1970 and 1977. The 1970 to 1977 units will provide approximately 57 percent of net generation in 1978. The oldest units, placed in service in 1961 or before will account for only 28 percent of capacity and 23 percent of net generation.

Some costs depend directly on age since the old equipment is too fragile to undergo major modifications. Moreover, when future plants are included in the analysis, age surpasses even capacity factor as a measure of cost/benefit, because the cost of retrofitting an old plant is about three times as large as the cost of installing closed-cycle cooling on a plant as original equipment.

ENVIRONMENTAL EVALUATION OF THE GUIDELINE OPTIONS

Each of the options considered by EPA was evaluated in terms of the environmental impact which would still exist under the guideline from exempted units.

Much attention was given to determining guidelines which would achieve the environmental objectives of the Act with the lowest economic cost.

THE MEASURES OF ENVIRONMENTAL IMPACT

The environmental "cost" associated with each option has been measured in terms of the percentage of high risk net generation which it would exempt. The guidelines proposed in March 1974 would have covered all but 3 percent of the high risk net generation by 1978, and all but 1 percent by 1983. However, the economic cost of those guidelines was significantly greater than that of the final guidelines which will exempt 44 percent of high risk net generation by 1983.[5]

For purposes of this analysis all steam electric generating units were categorized as:

- High risk - open-cycle units in which current or projected thermal effluent clearly poses an environmental hazard to the receiving body of water. Such units are: (a) those in plants on rivers with safezones less than 30 percent; (b) half of those units in plants on rivers with safezones between 30 percent and 70 percent; and (c) half of those units on estuaries and lakes.

---

5. *The projections of generating capacity used for the environmental assessment differ slightly from the final projections presented in the earlier chapters. Exhibit 89 compares the two and shows those used for the environmental analysis are 4.3 percent lower in 1974 and 1.4 percent lower in 1983.*

- low risk - open-cycle units in which current or projected thermal effluent does not appear to pose an environmental hazard to the receiving body of water. Such units are: (a) those in plants on rivers with safezones of over 70 percent; (b) half of those in plants on rivers with safezones between 30 and 70 percent; (c) half of those on estuaries and lakes; and (d) all employing water from municipal, sewage, ocean, and well sources.
- closed-cycle - units which are or will be operating closed-cycle cooling for economic reasons or in anticipation of the Act and which, therefore, pose no environmental hazard.

RISK PROFILE OF THE INDUSTRY

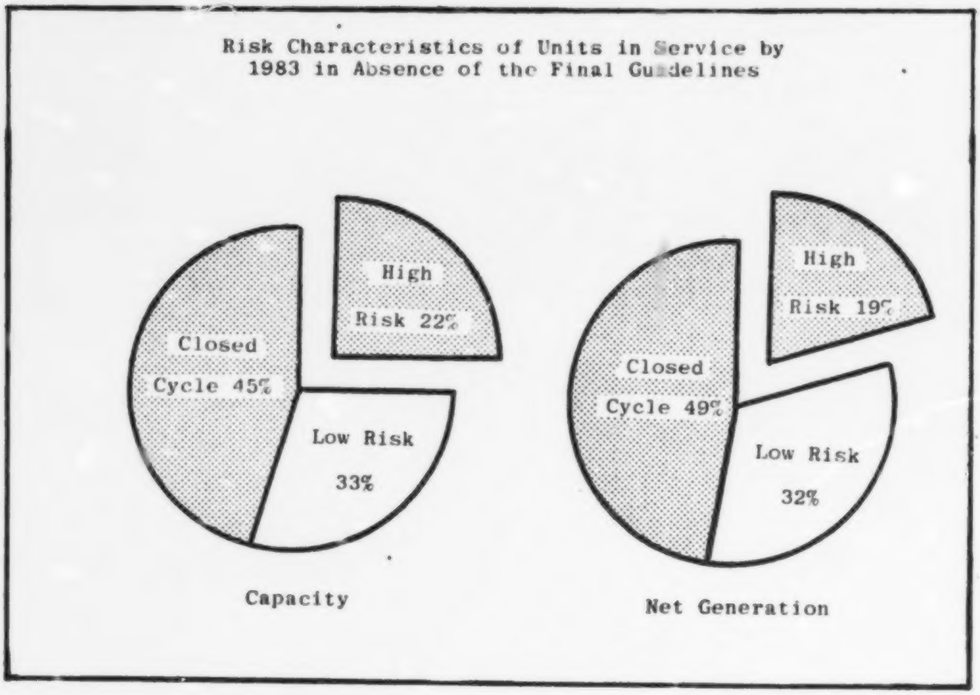
In the absence of environmental guidelines from EPA, 21.5 percent of the steam electric capacity in operation by 1983 will consist of high risk units. The risk characteristics of these units vary significantly as a function of age, as shown by Exhibit 90. Of the older, pre-1970 capacity which will still be in service by 1983 as much as 30 percent is high risk. In contrast, only 16 percent of the capacity coming into service between 1970 and 1983 will be high risk.

Underlying that trend is a significant shift to a higher share of closed-cycle cooling systems for economic reasons. Of the pre-1970 capacity which will still be in service by 1983, only 14 percent utilizes closed-cycle cooling. That figure jumped to 59 percent of all new units placed in service between 1970 and 1973, and will be up to 66 percent for those placed in service between 1974 and 1982.

By 1983, 58 percent of the capacity in operation will consist of post-1973 units or 1970-73 units larger than 500 megawatts, all of which will be covered by the final guidelines.

As a basis for estimating environmental risk, figures on net electric generation have been used in addition to capacity. For the economic analysis, capacity provides the best basis for estimating capital costs, but the environmental hazard is also directly related to utilization. The 21.5 percent high risk share of 1983 capacity is equivalent to a slightly lower percentage of 1983 net electric generation (19.4 percent), reflecting reduced utilization of the oldest, highest risk units.

The projected high risk share of 1983 capacity and net electric generation in the absence of guidelines is shown on the following page.



In 1970, 30 percent of net electric generation was from high risk units. By 1983, as a result of retirements and lower risk additions, that would decline to 19 percent even without federal guidelines.

Each of the guideline options was evaluated in terms of the percentage of 1983 high risk capacity and net generation which would be exempt. That which was covered would be shifted to closed-cycle cooling systems as a result of the guidelines. The sections below summarize the environmental risk evaluation for the major options considered.

THE FINAL OPTION

The final guidelines adopted by EPA will exempt all units in service prior to 1970 and those less than 500 megawatts in service between 1970 and 1973. Those units are the oldest and smallest units. As such, they have the lowest cost/benefit ratios and year-by-year will decline in utilization and be the first units to be retired. Therefore, cooling towers retrofitted to those units would have very high costs per kilowatt of capacity and would have unusually short lives.

The final guidelines will not cover 56 percent of the 1983 high risk capacity and 44 percent of the high risk net generation. That uncovered capacity accounts for 12 percent of total fossil and nuclear capacity and 10 percent of all capacity in that year. EPA has assumed that all high risk units which are not covered by the guidelines will not be exempt from State Water Quality Standards and, therefore, may be required to convert to closed-cycle cooling systems at some future time. The potential economic impact of State Water Quality Standards was analyzed in the preceding chapter.

THE MARCH 1974 PROPOSED OPTION

The proposed guidelines published March 4, 1974 would have exempted only units in service prior to 1950 and those in plants of less than 25 megawatt capacity or in systems of less than 150 megawatts. That standard would have exempted only 4 percent of high risk capacity and 1 percent of high risk net electric generation by 1983, or less than 1 percent of the total fossil and nuclear levels that year.

VARIATIONS ON THE FINAL OPTION

Changes from the 500 megawatt size criterion to be applied to 1970-73 units would have relatively small effects upon environmental risk unless increased to the point where even 700 to 1300 megawatt units would be exempt. Decreases in the criterion, as shown in Exhibit 91, would not substantially reduce the environmental risk. At the extreme, with no 1970-73 units exempt, 53 percent of the high risk capacity (11 percent of total fossil and nuclear capacity) would have been exempt. At a cutoff of 700 megawatts the exemptions increase only up to 59 percent.

However, increasing the cutoff up to 1300 megawatts, which would exempt all 1970-73 units, would increase the environmental risk to 66 percent.

ALTERNATIVE OPTIONS ON AGE

The environmental risk of the guidelines is most sensitive to variations in the age criterion in the guideline. Unfortunately, the economic impact is also most sensitive to this criterion as a result of the high cost of retrofitting cooling towers on existing plants.

The range of environmental risk as a function of this criterion is from 4 percent with a 1950 service year cutoff to 79 percent with a 1978 cutoff, as shown in Exhibit 92. A 1961 cutoff would yield 24 percent risk, while a 1970 limit doubles the percentage of high risk net generation exempted (52 percent).

OTHER OPTIONS CONSIDERED

In addition to these major options, consideration was given to a substantial number of others. Most were simply variations on unit size and age of those presented above.

Some, however, were examined which included capacity factor as a criterion. That was not incorporated into the final regulation in part, at least, because it would present very difficult enforcement problems. The capacity factor of a unit fluctuates both daily and annually, and in response to system demands, management policy, and maintenance schedules.

Age serves almost the same function which capacity factor would, because age and utilization are highly correlated, without the same administrative ambiguities. Furthermore, the use of age as the primary criterion has enabled EPA to reduce the cost of the guidelines to the industry by a significant amount while still insuring that almost all new units which will be in service through the end of the century will be covered.

VII. ALTERNATIVE ASSUMPTIONS SUBMITTED BY UWAG

INTRODUCTION

On 4 March 1974, the Environmental Protection Agency (EPA) published a notice of proposed rulemaking in the *Federal Register (39 FR 8294)* announcing its intention to establish limitations on the discharge of pollutants by existing and new point sources within the steam electric generating category.

The regulation as proposed was supported by two documents[1] which were made available to the public and circulated to interested persons at approximately the time of the publication of the proposed rulemaking. Prior to 4 March 1974 remarks on an initial draft of the *Development Document* were distributed and comments were solicited. The majority of comments received and EPA's response were described in the notice of proposed rulemaking.

---

[1] *Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category (March 1974); and Economic Analysis of Proposed Effluent Guidelines: Steam Electric Powerplants (March 1974). This latter document contained TBS analysis of the proposed guidelines.*

Interested parties were again invited to participate in the rulemaking by submitting written comments within 90 days of the publication date of the proposed regulation. In response to requests for additional time the period for public comment was extended for 23 more days.

Thereafter, EPA convened a public hearing on 11 and 12 July 1974 in order to afford an opportunity for those who had submitted comments to explain the substance of their position in detail and to determine EPA's interpretation of and basis for its proposals.

On 26 June 1974, the Utility Water Act Group (UWAG) - in conjunction with the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association - submitted perhaps the most detailed comments to EPA on the proposed thermal and chemical guidelines.[2] On the basis of these written comments, public hearings and subsequent interaction between EPA and UWAG representatives, general agreement was reached on the basic methodology to be utilized in evaluating the economic impact of the final guidelines.

---

[2] *Comments on EPA's Proposed Section 304 Guidelines and Section 306 Standards of Performance for Steam Electric Powerplants* (3 Volumes); and *Comments on EPA's Proposed Section 316(a) Regulations and Draft Guidance Manual*.

Minor differences in assumptions still remain - and the purpose of the following analysis is both to specify these differences and to evaluate their economic impact.

AREAS OF DIFFERENCE IN ASSUMPTIONS[3]

The differences in operating and financial assumptions which remain fall into two general categories. First, UWAG does not agree with some of the basic industry assumptions developed by the National Power Survey's Technical Advisory Committee on Finance (TAC-Finance). The specific assumptions on which disagreement exists deal with the most likely rate of future industry growth and the rates required by the capital market for issuance of long-term debt and preferred stock.

---

[3] *The bases for the UWAG assumptions are documents submitted to EPA by National Economic Research Associates, Inc. (NERA), UWAG's economic advisers.*

Second, UWAG does not accept the capital and operating cost factors assumed for both the thermal and chemical guidelines. The differences that remain include capital costs for closed-cycle cooling and chemical discharge cleanup, the operating costs for both thermal and chemical effluent reduction, and the cost of outage during which open-cycle cooling facilities would be converted to closed-cycle.

The economic impact of these differences in assumptions is analyzed in the following sections which focus on:

- the "cost" effect of assuming UWAG capital and operating cost factors with the baseline industry operating assumptions specified by the TAC-Finance;
- the "growth" effect of assuming the EPA capital and operating cost factors with the industry operating assumptions specified by UWAG; and
- the "interaction" effect of simultaneously using UWAG cost factors and UWAG industry operating assumptions.[4]

---

[4] *The "interaction" effect is the impact of these assumptions less (1) the impact of the final guidelines with EPA assumptions, and (2) the "cost" effect, and (3) the "growth" effect.*

These different effects are graphically depicted below:

Industry Operating Assumptions	Cost Factors		Relevant Baseline Conditions
	EPA	UWAG	
TAC-Finance	Final Effluent Guidelines	Cost Effect	TAC-Finance
UWAG	Growth Effect	Interaction Effect	UWAG

The "cost" effect of varying the cost factors will be analyzed first and will be segmented by type of guidelines - thermal and then chemical. Next, the baseline conditions will be adjusted to reflect the UWAG industry operating assumptions, and this new baseline will then become the basis for analyzing both the "growth" and "interaction" effects. In order to highlight the differences between EPA and UWAG assumptions, the economic and financial implications will be limited to those after consideration of Section 316(a) exemptions for the period 1974-83.

It should be noted that the capacity coverage levels used throughout this analysis were those estimated by EPA. While UWAG accepted the coverage levels assumed prior to 316(a) exemptions, they did not necessarily accept the levels estimated after 316(a), nor after 316(a) and State Water Quality Standards.

ALTERNATIVE THERMAL COST FACTORS

While general agreement exists on the methodology to be used in evaluating the economic impact of the thermal guidelines, EPA and UWAG differ in their estimates of the cost of constructing and operating closed-cycle cooling systems as required by the final guidelines.

CAPITAL COST FACTORS

The following table summarizes the differences in capital cost factors which remain:

THERMAL CAPITAL COST FACTORS

(expressed in 1972 Dollars/Kilowatt)

	EPA Estimate	UWAG Estimate
For Retrofitted Units		
Non-Nuclear	$20.43	$22.44
Nuclear	24.58	27.01
For New Units		
Non-Nuclear	$ 4.89	$ 6.40
Nuclear	3.84	4.27

These estimates of capital costs are significantly closer than those which prevailed after the publication of the proposed guidelines. The remaining differences can be attributed to:

- differences in the base period and inflation rates used to convert the estimates to a consistent basis for comparison, and
- differences in the mix of cooling equipment assumed to be installed.

EPA has assumed that the capital cost associated with the Act should be based upon mechanical draft cooling towers; whereas, UWAG assumed a mix of mechanical and the more expensive natural draft towers which they believe approximated the existing distribution of cooling towers.

OPERATING COST FACTORS

UWAG assumptions for the cost of installing, operating, and maintaining closed-cycle cooling systems differ from those of EPA in two ways. First, UWAG has assumed that the annual operating cost for replacement capacity differs from EPA estimates as follows:

THERMAL ANNUAL OPERATING COST FACTORS FOR REPLACEMENT CAPACITY

(Expressed in 1972 Dollars/Kilowatt)

	EPA Estimates	UWAG Estimates
For Retrofitted Units		
Non-Nuclear	$ 39.41	$130.09
Nuclear	39.41	130.09
For New Units		
Non-Nuclear	$ 39.43	$ 84.56
Nuclear	23.12	23.12

This variability in estimates results from a difference in the assumptions underlying the computations, not in the methodology employed to determine these costs.

Specifically, EPA assumed that new capacity would be utilized with the operating costs based upon: (1) an average heat rate of 10,000 BTU per kilowatt hour, (2) a fuel mix of 80 percent coal and 20 percent oil, and (3) fuel prices of $7.00 per barrel for oil and $12.50 per ton for coal. Since replacement capacity need not be placed in service before 1981, adequate time exists for installation of new capacity.

UWAG, on the other hand, assumed that the appropriate basis for computing the annual operating costs for new plants would be: (1) an average heat rate of 10,000 BTU, (2) a fuel mix of 50 percent coal and 50 percent oil, and (3) fuel prices of $12 per barrel for oil and $25 per ton for coal. For existing plants, UWAG based its analysis upon equal usage of residual oil, coal, and distillate with corresponding heat rates of 12,500, 12,500 and 15,000 BTU.

Second, UWAG and EPA differ on the computational procedure to be employed in estimating the costs associated with operating less efficient generating equipment during the period in which capacity being converted from open to closed-cycle cooling is out of service.

EPA assumed that the installation of closed-cycle cooling on existing units or units under construction but designed for open-cycle cooling would require a downtime period of one month in addition to the normal maintenance period. During this period, it was assumed that the lost generation capability would be made up by utilization of peaking capacity with an incremental increase in heat rate of 2,500 BTU/KWH (12,500 less 10,000) with the same fuel mix and fuel costs used in computing the total operating costs for replacement capacity.

UWAG's computations reflect alternative sets of conditions prevailing at the time of installation. First, replacement capacity - if available during the period of outage - would be relatively inefficient cycling or peaking equipment. Second, for systems with insufficient capacity to handle these outages, the next option would be purchased power from other utilities. Third, for those utility systems which would be unable to purchase additional power from surrounding systems, outages would require the purchase of peaking units.[5] In this last case, both the additional fuel cost and the capital cost must be reflected.

---

[5] *The final regulation specifies that up to a two-year delay in installation schedule can be granted where such conversions would seriously impact system reliability.*

These differences in underlying assumptions are summarized in the following table.

THERMAL OUTAGE COST FACTORS
(Expressed in 1972 Dollars/Kilowatt)

	EPA Estimates	UWAG Estimates
For Retrofitted Units		
Non-nuclear	$ 1.08	$ 4.46
Nuclear	.89	7.81

IMPACT OF COST FACTORS (THERMAL)

In order to estimate the economic impact of the alternative cost factors developed by UWAG, two additional cases were evaluated:

- UWAG Case #1 - Projections which correspond to those previously associated with the installation of closed-cycle cooling for economic reasons, except that the thermal cost factors - both capital and annual operating - are those assumed by UWAG; and
- UWAG Case #2 - Projections which correspond to those previously analyzed after consideration of 316(a) exemptions, except that the thermal cost factors are those assumed by UWAG.

These cases, along with the previously cited baseline conditions, economic reasons, and after 316(a) exemptions are provided in Exhibit 93 for the period 1974-83.

Prior to evaluating the effect of altering the cost factors upon the economic impact of the Act, one must first determine the increased impact of installing closed-cycle cooling for reasons other than environmental. Having computed the difference attributed to installation of closed-cycle cooling for economic reasons, the following table summarizes the impact of the thermal guidelines after considering the exemptions available under Section 316(a) of the Act.

COST EFFECT OF UWAG ASSUMPTIONS
THERMAL (1974-1983)
(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH)
UWAG Cost Factors	$ 2.9	$ 2.2	0.3
EPA Cost Factors	2.7	0.9	0.2
Difference	$ 0.2	$ 1.3	0.1

Thus, the cost effect of utilizing the UWAG assumptions for thermal cost factors is an increase in capital expenditures of $200 million in the next decade, a $1.3 billion increase in operating costs during the same period, and a 0.1 mill increase in the 1983 average cost per kilowatt-hour. The relatively large increase in operations and maintenance expenses primarily reflects the assumed significant increase in fuel prices.

ALTERNATIVE CHEMICAL COST FACTORS

Perhaps the most diverse estimates are those associated with the capital and operating cost factors required to meet the final chemical guidelines. EPA and UWAG were unable to resolve all of the different assumptions - and the cost factors discussed below reflect these differences.

CAPITAL COST FACTORS

The following tables summarize the differences in capital cost factors:

CHEMICAL CAPITAL COST FACTORS: NON-NUCLEAR

(Expressed in 1972 Dollars/Kilowatt)

	EPA Estimate	UWAG Estimate
Capacity prior to 1974		
1977 Guidelines	$ 1.70	$ 5.78
1983 Guidelines[6]	0.58	-
Capacity 1974-78		
1977 Guidelines	$ 1.29	$ 4.58
1983 Guidelines[6]	0.52	-
Capacity 1979-90		
1983 Guidelines	$ 1.63	$ 3.18

---

[6] *These capital expenditures are in addition to those required to meet the 1977 guidelines.*

CHEMICAL CAPITAL COST FACTORS: NUCLEAR
(Expressed in 1972 Dollars/Kilowatt)

	EPA Estimate	UWAG Estimate
Capacity Prior to 1974		
1977 Guidelines	$ 0.58	$ 0.53
1983 Guidelines[7]	-	-
Capacity 1974-78		
1977 Guidelines	$ 0.58	$ 0.53
1983 Guidelines[7]	-	-
Capacity 1979-90		
1983 Guidelines	$ 0.48	$ 0.51

The variation in capital costs for non-nuclear generating capacity is significant and should have a significant effect upon the capital expenditures required to meet the chemical guidelines. The differences for nuclear capacity are not significant.

OPERATING COST FACTORS

The following tables summarize the differences in annual operating cost factors:

---

[7] *These capital expenditures are in addition to those required to meet the 1977 guidelines.*

CHEMICAL ANNUAL OPERATING COST FACTORS: NON-NUCLEAR

(Expressed in 1972 Dollars/Kilowatt)

	EPA Estimate	UWAG Estimate
Capacity prior to 1974		
1977 Guidelines	$0.54	$0.61
1983 Guidelines[8]	0.06	–
Capacity 1974-78		
1977 Guidelines	$0.25	$0.48
1983 Guidelines[8]	0.02	–
Capacity 1979-90		
1983 Guidelines	$0.25	$0.50

CHEMICAL ANNUAL OPERATING COST FACTORS: NUCLEAR

(Expressed in 1972 Dollars/Kilowatt)

	EPA Estimate	UWAG Estimate
Capacity prior to 1974		
1977 Guidelines	$0.20	$0.004
1983 Guidelines[8]	–	–
Capacity 1974-78		
1977 Guidelines	$0.20	$0.004
1983 Guidelines[8]	–	
Capacity 1979-90		
1983 Guidelines	$0.20	$0.006

---

[8] These annual operating expenditures are in addition to those required to meet the 1977 guidelines.

These differences are rather insignificant when compared with the absolute differences in capital costs for non-nuclear capacity.

IMPACT OF COST FACTORS (CHEMICAL)

In order to estimate the economic impact of the alternative chemical cost factors developed by UWAG, an additional case was evaulated:

- UWAG Case #3: Projections which correspond to those previously associated with the chemical guidelines, except that the chemical cost factors are those assumed by UWAG.

This case along with the previously cited baseline conditions and chemical guidelines are provided in Exhibit 94 for the period 1974-83.

The cost effect of the UWAG assumptions for chemical cost factors is summarized in the following table:

COST EFFECT OF UWAG ASSUMPTIONS
CHEMICAL (1974-83)
(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	Consumer Charges (mills/KWH)
UWAG Cost Factors	$3.1	$2.0	0.2
EPA Cost Factors	1.3	2.1	0.2
Difference	$1.8	($0.1)	0.0

Thus, the differences in chemical cost factors more than double the required capital expenditures - by $1.8 billion. This impact far exceeds the differential impact for thermal cost factors. The impact of utilizing UWAG assumptions has an insignificant effect upon chemical O/M expenses and the average cost of electrical energy in 1983.

ALTERNATIVE BASELINE CONDITIONS

While UWAG accepted the vast majority of TAC-Finance assumptions for future operating conditions which were incorporated into the baseline projections detailed in Chapter II, two areas of disagreement remain.

First, UWAG does not accept the TAC-Finance position that the most likely rate of industry growth will be moderate after the short-run adjustments to reflect the recent energy crisis (TAC-Finance Cases I and IA). Instead, UWAG has proposed that the appropriate baseline projections should incorporate the alternative historical growth rate assumptions described in Chapter II of this report (TAC-Finance Case II).

Second, UWAG does not believe that current rates for interest on long-term debt and dividends on preferred stock will stabilize at 8 percent. UWAG has proposed that the long-run rate for these financing instruments will approximate 10 percent.

ECONOMIC IMPACT

The alternative set of baseline conditions proposed by UWAG required the evaluation of an additional case:

- UWAG Case #4 - Projections which correspond to the previously mentioned baseline conditions, except that the rate of industry growth is the historic rate and the capital market rates are those assumed by UWAG.

This case, along with previously cited baseline and historic conditions, is provided in Exhibit 95 for the period 1974-83.

The following tables separately summarize the economic impact upon baseline conditions of alternative rates of industry growth and alternative capital market assumptions:

BASELINE CONDITIONS WITH ALTERNATIVE GROWTH RATES (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH)
Historic Growth	$211.7	$306.6	23.9
Moderate Growth	179.0	292.5	23.6
Difference	$ 32.7	$ 14.1	0.3

BASELINE CONDITIONS WITH HISTORIC GROWTH AND ALTERNATIVE CAPITAL MARKET RATES (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenditures (in billions)	1983 Consumer Charges (mills/KWH
UWAG Interest and Preferred Dividend Rates	$211.7	$306.6	24.6
NPS Interest and Preferred Dividend Rates	211.7	306.6	23.9
Difference	$ 0.0	$ 0.0	0.7

Thus, one can easily conclude that the baseline level of expenditures is greatly influenced by the assumed rate of growth and that the impact of these differences is significantly greater than the above-mentioned differences in cost factors. In addition, the capital market assumption for future rates of interest on long-term debt and dividends on preferred stock have a significant impact upon the 1983 cost of electricity but no effect on expenditure levels.

The amount of generating capacity which is covered under the guidelines of the Act increases with the change in the growth rate of the electric utility industry from moderate to historic. This increase in capacity required to install closed-cycle cooling - when coupled with the cost factors assumed by EPA - impacts the economic costs associated with the Act. These growth effects have been separated from the direct cost effects of utilizing UWAG cost factors since they are the result of higher industry growth and capital market conditions - and not higher cost factors.

In addition to these indirect growth effects, the interaction effects of simultaneously considering the higher growth assumptions and the higher cost factors proposed by UWAG must be evaluated separately.

IMPACT OF GROWTH ASSUMPTIONS (THERMAL)

The indirect effect of UWAG growth and capital market assumptions upon the economic impact of the final thermal guidelines after consideration of 316(a) can be evaluated after specification of two additional cases:

- UWAG Case #5 - Projections which correspond to those previously associated with the installation of closed-cycle cooling for economic reasons, except that the industry growth and capital market assumptions are those assumed by UWAG; and
- UWAG Case #6 - Projections which correspond to those previously analyzed after consideration of 316(a) exemptions, except that the industry growth and capital market assumptions are those assumed by UWAG.

These projections, along with the revised UWAG baseline conditions (UWAG Case #4) are provided in Exhibit 96 for the period 1974-83.

The following table summarizes the growth effect associated with closed-cycle cooling after consideration of 316(a) exemptions.

GROWTH EFFECT OF UWAG ASSUMPTIONS - THERMAL (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH
UWAG Baseline	$3.1	$1.1	0.2
NPS Baseline	2.7	0.9	0.2
Difference	$0.4	$0.2	0.0

Thus, the indirect growth effect of utilizing the UWAG baseline conditions with the EPA cost factors is small - after deducting those units with closed-cycle cooling for economic reasons and after exempting those units eligible for 316(a) exemptions. The UWAG growth assumptions would increase capital expenditures by $400 million during the next decade and O/M expenses by $200 million.

IMPACT OF INTERACTION EFFECT (THERMAL)

In addition to the direct cost and indirect growth effects of UWAG assumptions upon the economic impact of the thermal guidelines, the interaction of higher growth and higher cost factors combined result in an increase in the overall impact. This interaction effect requires the specification of two additional cases:

- UWAG Case #7 - Projections which correspond to those previously associated with the installation of closed-cycle cooling for economic reasons, except that the baseline conditions and cost factors are those assumed by UWAG; and
- UWAG Case #8 - Projections which correspond to those previously analyzed after consideration of 316(a) exemptions, except that the baseline conditions and cost factors are those assumed by UWAG.

These cases along with the revised baseline conditions (UWAG Case #4), are provided in Exhibit 97 for the period 1974-83.

The following table summarizes the interaction effects of alternative baseline and thermal cost factor assumptions associated with closed-cycle cooling after consideration of 316(a) exemptions.

INTERACTION EFFECT OF UWAG ASSUMPTIONS
THERMAL (1973-83)
(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH
UWAG Cost Factors	$3.4	$2.7	0.4
All Other Effects[9]	3.3	2.4	0.3
Difference	$0.1	$0.3	0.1

Thus, the interaction effect of alternative baseline conditions and cost factors combine to increase the economic impact of the thermal guidelines during the next decade by $200 million for capital expenditures, $300 million for operating expenses, and 0.1 mill for the average consumer charge per kilowatt-hour.

---

[9] *Includes economic impact of final guidelines plus cost effect plus growth effect.*

IMPACT OF GROWTH ASSUMPTIONS (CHEMICAL)

The indirect growth of UWAG growth and capital market assumptions can be evaluated by specifying an additional case:

- UWAG Case #9 - Projections which correspond to those previously associated with the final chemical guidelines except that the industry growth and capital market assumptions are those assumed by UWAG.

These projections, along with the revised UWAG baseline conditions (UWAG Case #4), are provided in Exhibit 98 for the period 1974-83.

The following table summarizes the indirect growth effect of the thermal guidelines:

GROWTH EFFECT OF UWAG ASSUMPTIONS CHEMICAL (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH)
UWAG Baseline	$ 1.5	$ 2.1	0.2
EPA Baseline	1.3	2.1	0.2
Difference	$ 0.2	$ 0.0	0.0

Thus, the indirect growth effect of utilizing the UWAG baseline conditions with the EPA cost factors is small - amounting to an increase in capital expenditures of $200 million.

IMPACT OF INTERACTION EFFECT (CHEMICAL)

The interaction of UWAG baseline conditions and UWAG chemical cost factors combined can be evaluated by specifying an additional case:

- UWAG Case #10 - Projections which correspond to those previously associated with the final chemical guidelines, except that the baseline conditions and cost factors are those assumed by UWAG.

These projections are included in Exhibit 98.

The following table summarizes the interaction effect of alternative baseline and chemical cost factor assumptions:

INTERACTION EFFECT OF UWAG ASSUMPTIONS CHEMICAL (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH)
UWAG Cost Factors	$3.3	$2.1	0.3
All Other Effects[10]	3.3	2.0	0.2
Difference	$0.0	$0.1	0.1

---

[10] *Includes economic impact of final guidelines plus cost effect plus growth effect.*

Thus, the interaction effect has a slight impact upon O/M expenses ($100 million) over the next decade and increases consumer charges by 0.1 mill per kilowatt-hour by 1983. These differences are primarily a result of rounding errors.

SUMMARY

In order to appropriately assess the economic impacts of alternative assumptions proposed by UWAG, TBS segmented the impact into the direct cost effect of higher capital and operating cost factors, the indirect growth effect of historic baseline conditions, and the interaction effect of simultaneously considering both of the above.

Furthermore, it is the opinion of TBS that only the direct cost effect is the appropriate measure of the differences that remain between EPA and UWAG. The other effects are associated with the growth assumptions wherein the EPA assumptions correspond quite closely to the recent revised forecasts published in *Electrical World*.

THERMAL GUIDELINES

The total impact of the UWAG assumptions upon the thermal guidelines after consideration of 316(a) exemptions is summarized in the following table:

ECONOMIC IMPACT OF UWAG ASSUMPTIONS UPON THERMAL GUIDELINES (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH)
Cost Effect	$0.2	$ 1.3	0.1
Growth Effect	0.4	0.2	0.0
Interaction Effect	0.1	0.3	0.1
Difference	$0.7	$ 1.8	0.2

Thus, the total impact of the UWAG assumptions is to increase the capital expenditures required during the next decade to meet the thermal guidelines from $2.7 to $3.4 billion. In addition, O/M expenses - primarily a result of a near doubling in the cost of fossil fuel - increase from $0.9 to $2.7 billion during the next decade. The total of these increases is projected to increase the average cost of a kilowatt-hour of electricity by 0.2 mill by 1983.

CHEMICAL GUIDELINES

The total impact of the UWAG assumptions upon the chemical guidelines is summarized in the following table:

ECONOMIC IMPACT OF UWAG ASSUMPTIONS UPON CHEMICAL GUIDELINES (1974-83)

(1974 Dollars)

	Capital Expenditures (in billions)	O/M Expenses (in billions)	1983 Consumer Charges (mills/KWH)
Cost Effect	$1.8	$(0.1)	0.0
Growth Effect	0.2	0.0	0.0
Interaction Effect	0.0	0.1	0.1
Difference	$2.0	$ 0.0	0.1

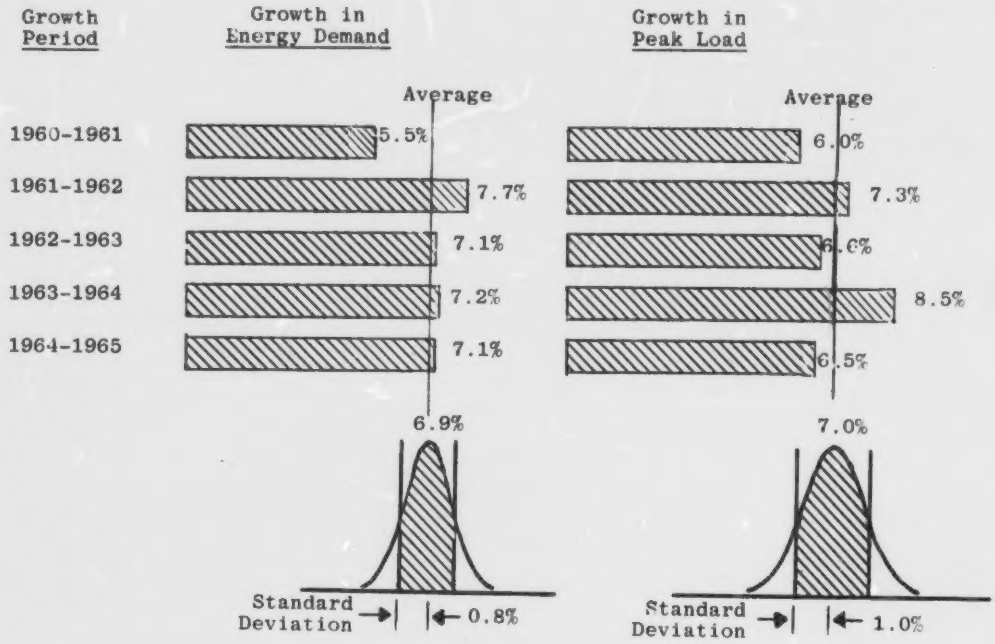
Thus, the total impact of the UWAG assumptions is to increase the capital expenditures required during the next decade to meet the chemical guidelines from $1.3 to $3.3 billion - primarily as a result of widely different capital cost assumptions for non-nuclear capacity. This increase in capital expenditures is nearly three times the increase resulting from differences in thermal cost factors.

In addition, O/M expenses are not expected to increase as a result of different assumptions - once again a marked contrast with the conclusion for the thermal guidelines. These increases should result in a 0.1 mill increase in the average cost of a kilowatt-hour by 1983.

Exhibits

Exhibit 1

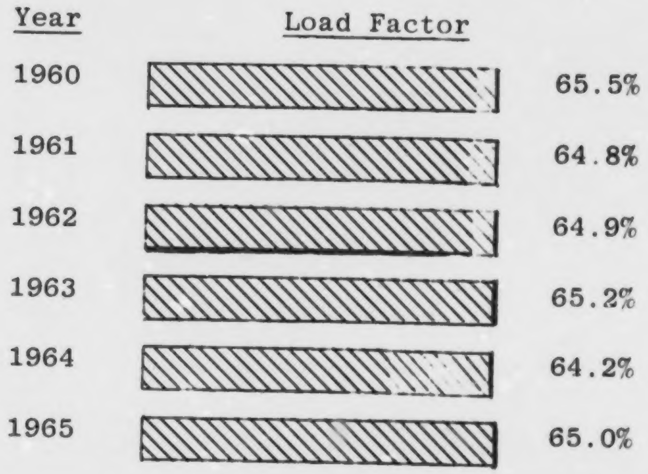
GROWTH IN ENERGY DEMAND AND IN PEAK LOAD RELATIVELY PREDICTABLE THROUGH EARLY 1960s



Sources: EEI, Electrical World

Exhibit 2

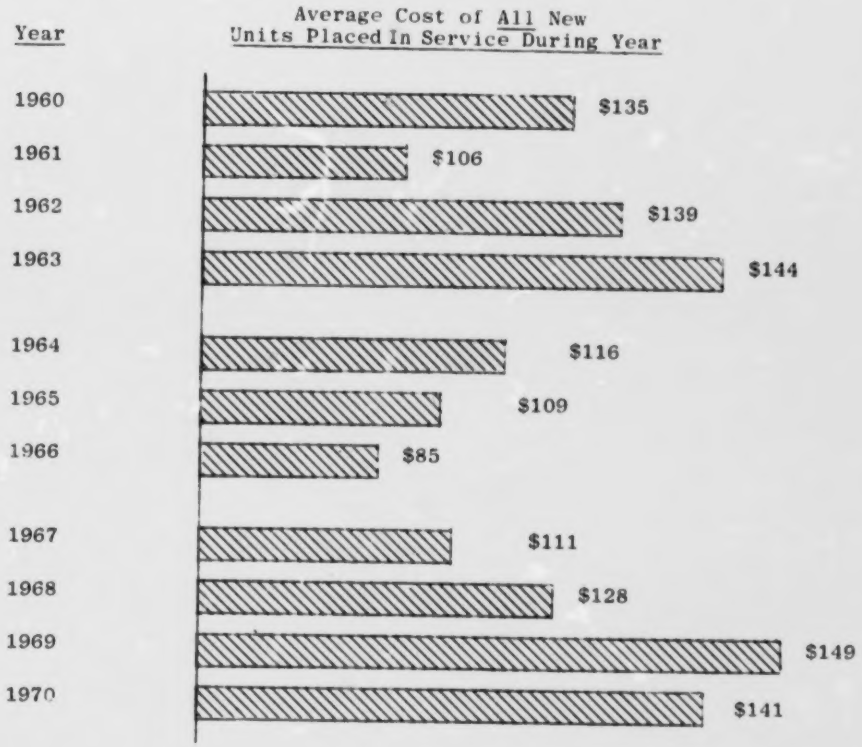
ANNUAL LOAD FACTOR REMARKABLY CONSTANT THROUGH EARLY 1960s



Source: EEI

Exhibit 3

COST PER KILOWATT OF INSTALLED CAPACITY AT END OF 1960s WAS ABOUT SAME LEVEL AS AT START



Source FPC

Exhibit 4

INVESTMENT IN ELECTRIC PLANT PER DOLLAR OF REVENUE QUITE CONSTANT DURING EARLY 1960s

Year	Investment Per Dollar of Electric Revenue
1960	$4.49
1961	4.51
1962	4.45
1963	4.45
1964	4.44
1965	4.46
1966	4.46

Source: FPC

Exhibit 5

CAPITAL EXPENDITURES GREW VERY SLOWLY IN EARLY 1960s

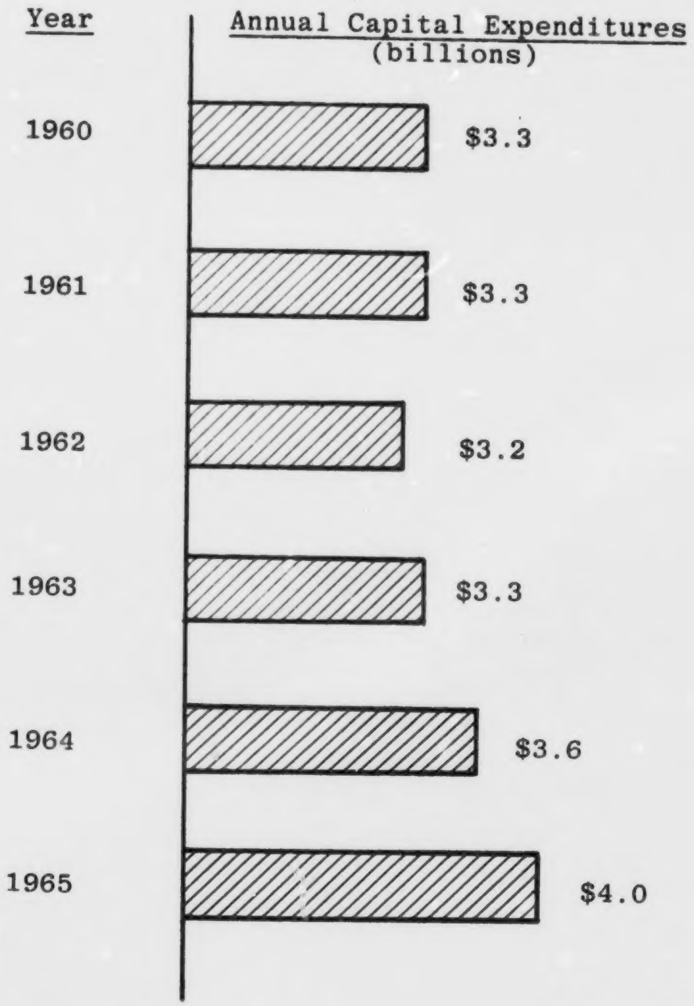


Exhibit 6

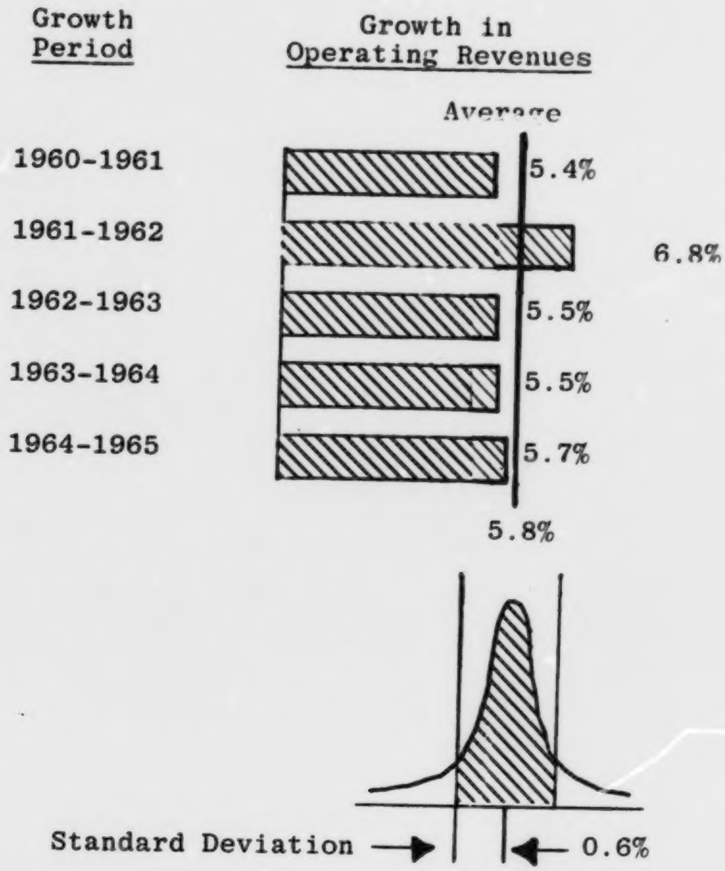
COST PER KILOWATT-HOUR - BOTH TOTAL AND MAJOR COMPONENTS - DECLINED DURING EARLY 1960s

Year	Total Cost Per kWh	Operations & Maintenance Costs Per kWh			Interest Cost Per kWh	All Other Costs Per kWh
		Excluding Fuel	Fuel Only	Total		
1960	16.3 mills	5.8 mills	2.9 mills	8.7 mills	1.2 mills	6.4 mills
1961	16.3	5.7	2.9	8.6	1.2	6.5
1962	16.0	5.6	2.9	8.5	1.2	6.3
1963	15.7	5.5	2.8	8.3	1.2	6.2
1964	15.4	5.4	2.8	8.2	1.1	6.1
1965	15.1	5.4	2.7	8.1	1.1	5.9
1966	14.9	5.3	2.8	8.1	1.1	5.7

Sources: FPC, EEI, TBS Estimates

Exhibit 7

GROWTH IN REVENUES STEADY AND CONSISTENT THROUGH EARLY 1960s



Source: FPC

Exhibit 8

RATES DECLINED ALONG WITH REVENUES PER KWH THROUGH THE EARLY 1960s

Year	Average Bill for Residential Service 500 kWh	 250 kWh	Revenue Per kWh All Customers
1960	$10.62	$7.44	1.69¢
1961	10.64	7.45	1.69
1962	10.66	7.48	1.68
1963	10.64	7.48	1.65
1964	10.61	7.43	1.62
1965	10.41	7.38	1.59
Total Change 1960-1965	-2.0%	-0.8%	-5.9%

Sources: FPC, EEI

Exhibit 9

NUMBER OF CUSTOMERS AND AVERAGE USAGE PER CUSTOMER INCREASED SIGNIFICANTLY DURING THE EARLY 1960s

Period	Total Customers	kWh Per Customer
1960	58,870,000	11,605
1961	60,130,000	11,986
1962	61,324,000	12,656
1963	62,857,000	13,218
1964	64,148,000	13,880
1965	65,558,000	14,543
Total Change	+11.4%	+25.3%

Sources: EEI

Exhibit 10

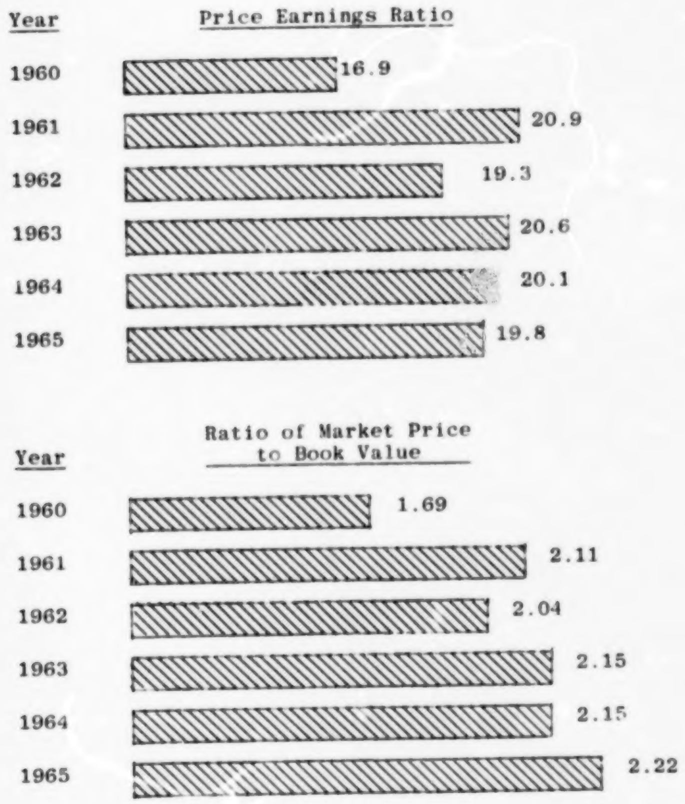
FINANCIAL RESULTS GOOD THROUGH THE EARLY 1960s

Year	Net Income (in millions)	Earnings Per Share	Return on Common Equity	Return on Total Investment
1960	$1,666	$ 4.12	11.7%	6.4%
1961	1,741	4.33	11.6	6.4
1962	1,954	4.73	12.4	6.8
1963	2,100	4.99	12.7	7.0
1964	2,185	5.41	12.5	6.9
1965	2,381	5.92	12.9	7.2
Overall Increase	42.9%	43.7%		
Average Annual Increase	8.6%	8.7%		

Sources: FPC, TBS estimates

Exhibit 11

INDICATORS OF INVESTMENT CLIMATE IMPROVED SIGNIFICANTLY DURING EARLY 1960s



Source: Moody's Public Utilities Manual

Exhibit 12

UTILITY MANAGEMENT SHIFTED THEIR CAPITALIZATION TOWARD EQUITY DURING THE EARLY 1960s

	Capitalization Ratios	
Year	**Long-Term Debt**	**Common Equity**
1960	52.8%	36.5%
1961	52.8	36.8
1962	52.4	37.3
1963	52.1	37.9
1964	51.8	38.6
1965	51.5	39.0

Source: *Moody's Public Utilities Manual*

Exhibit 13

INTERNALLY GENERATED FUNDS BECAME MORE IMPORTANT DURING THE EARLY 1960s AS BOTH NEW DEBT AND EQUITY TAPERED OFF

Year	Total Sources of Funds	External Funds		Internal Funds
		Debt	New Equity	
	(in millions)			
1960	$3,660	$1,226	$704	$1,729
1961	3,359	996	633	1,729
1962	3,359	764	610	1,984
1963	3,336	829	747	1,759
1964	3,832	1,008	704	2,119
1965	4,078	1,261	521	2,294
Totals	$21,624	$6,084	$3,919	$11,614
1960-1962 Percent	100%	29%	19%	52%
1963-1965 Percent	100%	28%	17%	55%

Source: FPC

Exhibit 14

INDUSTRIAL BOND RATE VIRTUALLY CONSTANT UNTIL 1965, THEN MOVED SHARPLY UPWARD

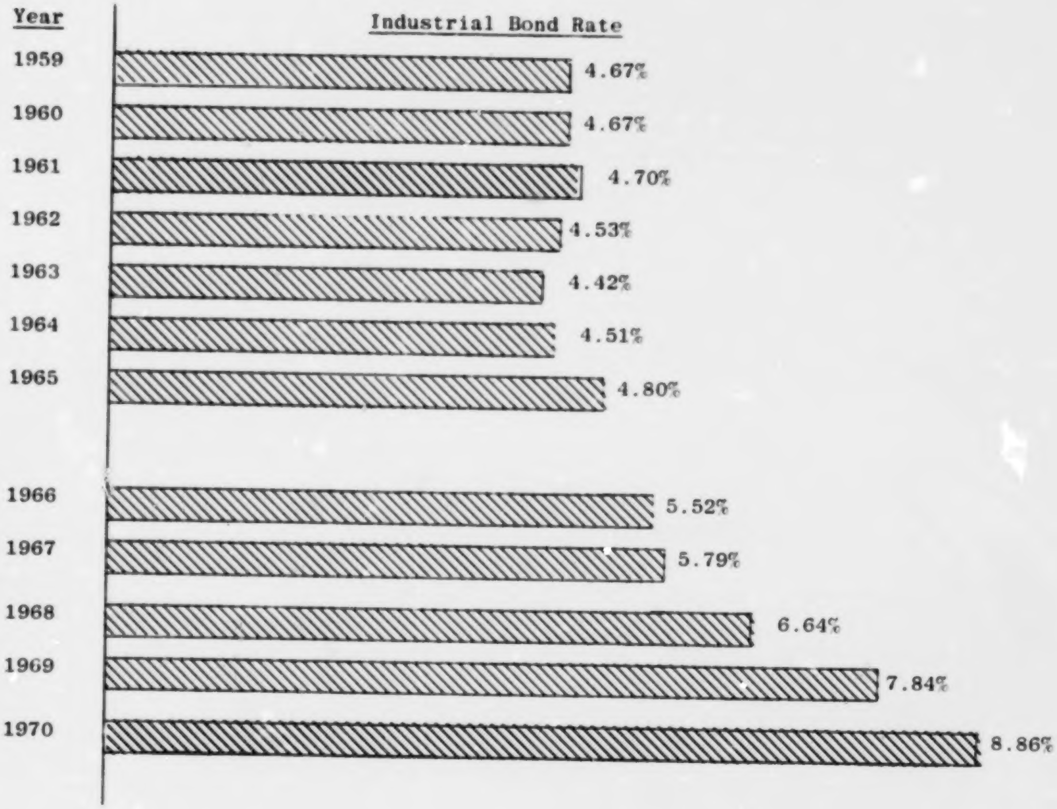


Exhibit 15

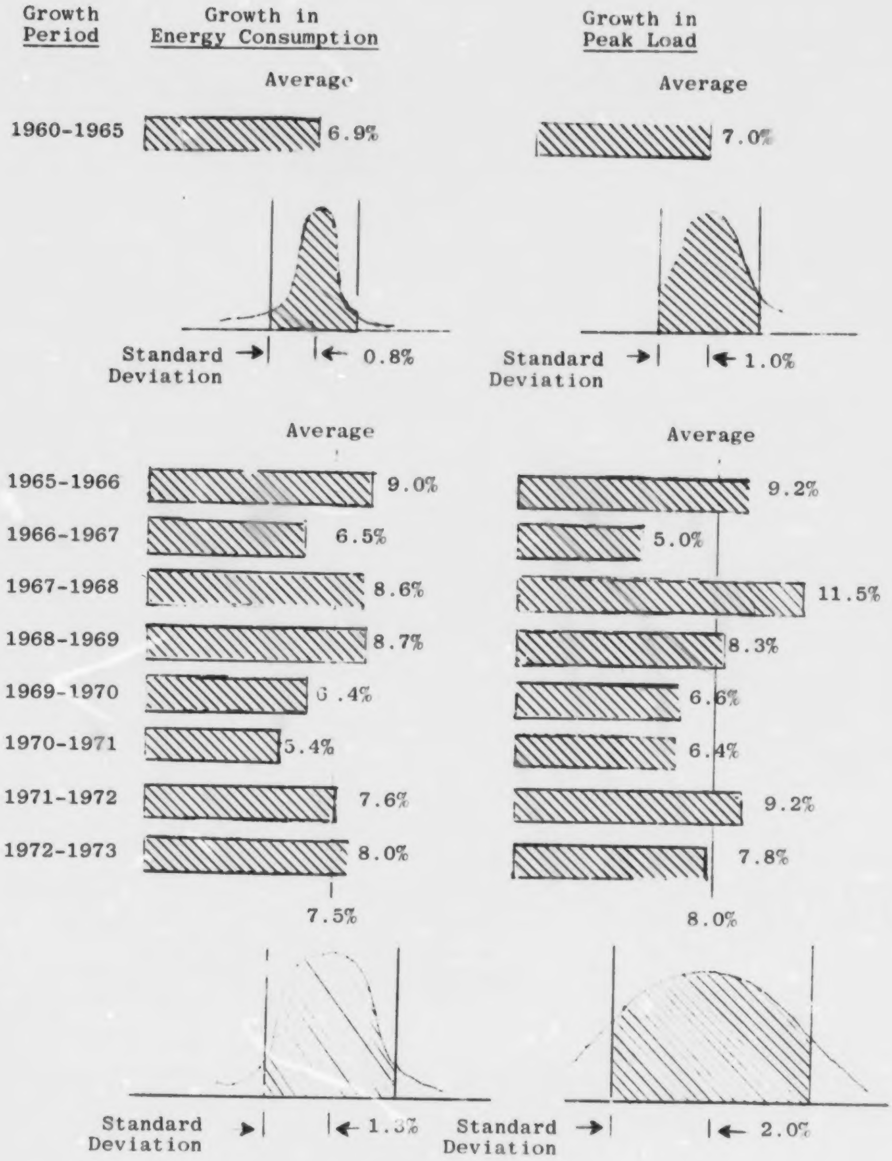
REQUIREMENTS FOR EXTERNAL FINANCING HAVE GROWN DRAMATICALLY SINCE MID-1960s

Year	Total Sources of Funds	External Funds	Percent External
1965	$ 4,078	$ 1,784	43.7%
1960-1965 Total	21,624	10,010	46.3
1966	5,551	3,039	54.7
1967	6,160	3,618	58.7
1968	7,101	4,260	60.0
1969	7,983	4,817	60.3
1970	11,043	7,778	70.4
1971	12,520	8,930	71.3
1972	14,142	9,736	68.8
1973	14,902	10,214	68.5
1966-1973 Average	79,402	52,392	66.0

Source: FPC

Exhibit 16

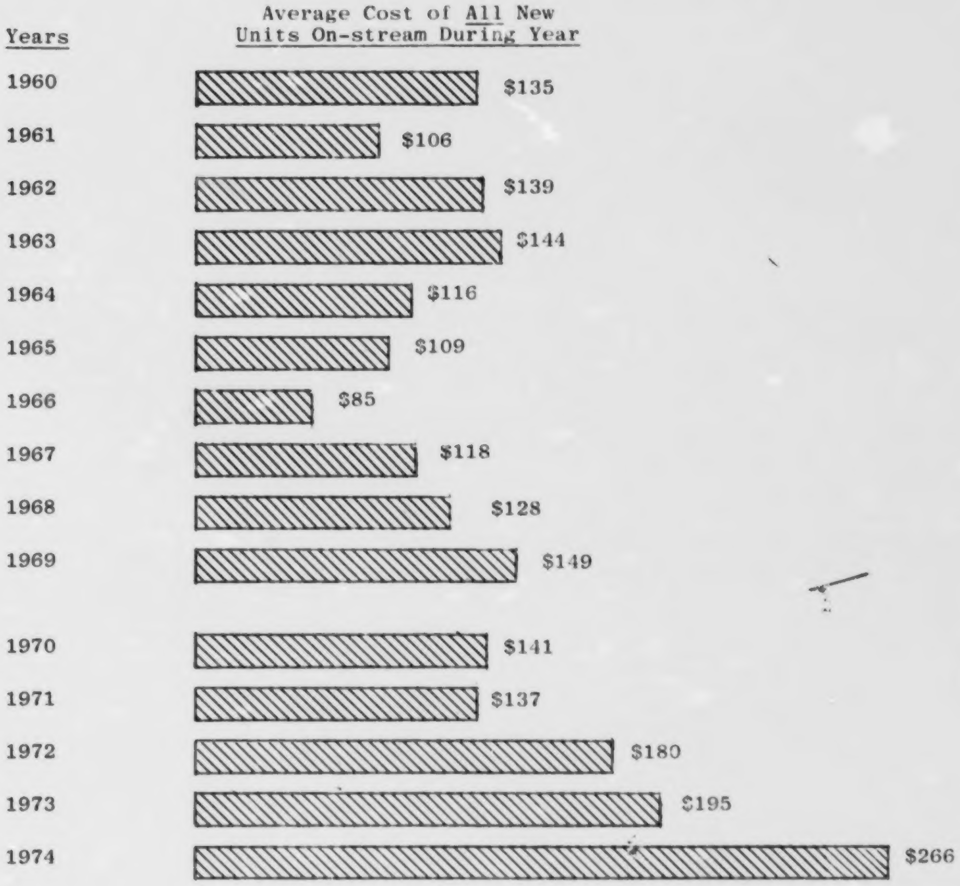
GROWTH IN ENERGY CONSUMPTION AND IN PEAK LOAD ACCELERATED SINCE THE EARLY 1960s AND PREDICTABILITY DETERIORATED



Source: EEI, Electrical World

Exhibit 17

COST PER KW OF INSTALLED CAPACITY INCREASED DRAMATICALLY SINCE THE 1960s



Sources: FPC, Power Engineering, TBS estimates

Exhibit 18

CAPITAL EXPENDITURES - AFTER A PERIOD OF RELATIVE CONSTANCY IN EARLY 1960s - HAVE GROWN RAPIDLY SINCE THAT TIME

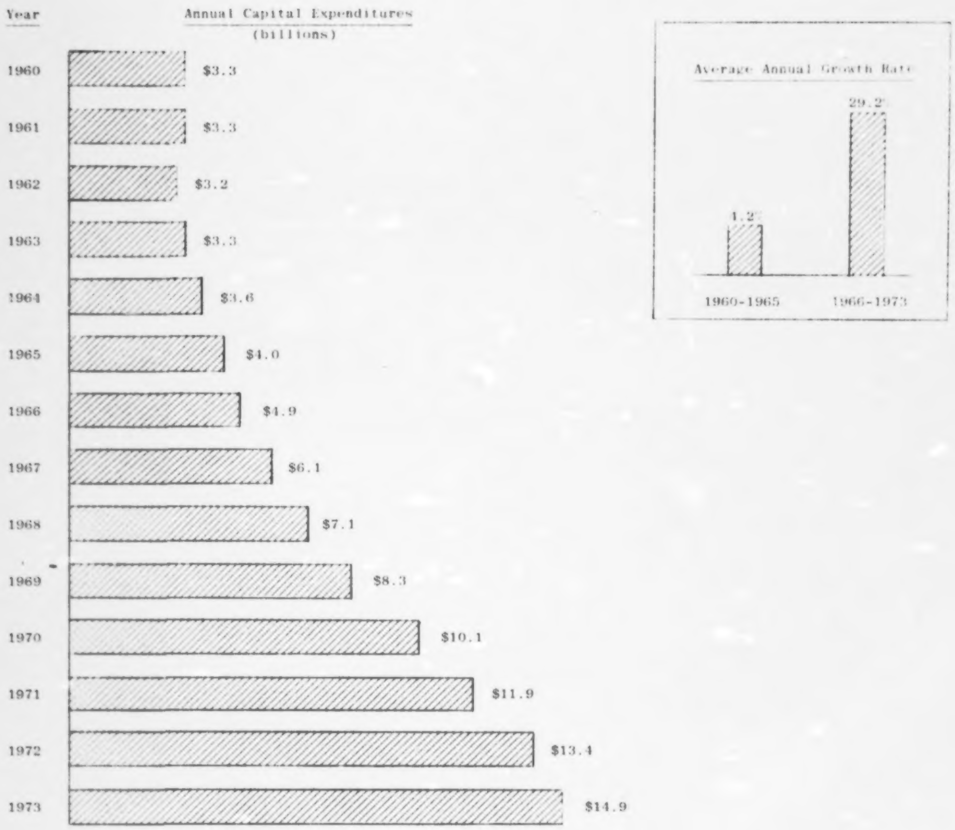


Exhibit 19

INTERNALLY GENERATED FUNDS NOT GROWING AS FAST AS NEED FOR FUNDS SINCE 1965

	Year-to-Year Growth Rate	
Year	Internal Funds	Need for Funds
1960-1961	0.0%	-8.2%
1961-1962	14.7	0.0
1962-1963	-11.3	-0.7
1963-1964	20.5	14.9
1964-1965	8.3	6.4
1965-1966	9.5	36.1
1966-1967	1.2	11.0
1967-1968	11.8	15.3
1968-1969	11.4	12.4
1969-1970	3.1	38.3
1970-1971	10.0	13.4
1971-1972	22.7	13.0
1972-1973	6.4	5.4
1960-1965 Average Rate	6.4%	2.5%
1965-1973 Average Rate	9.5%	18.1%

Source: FPC

Exhibit 20

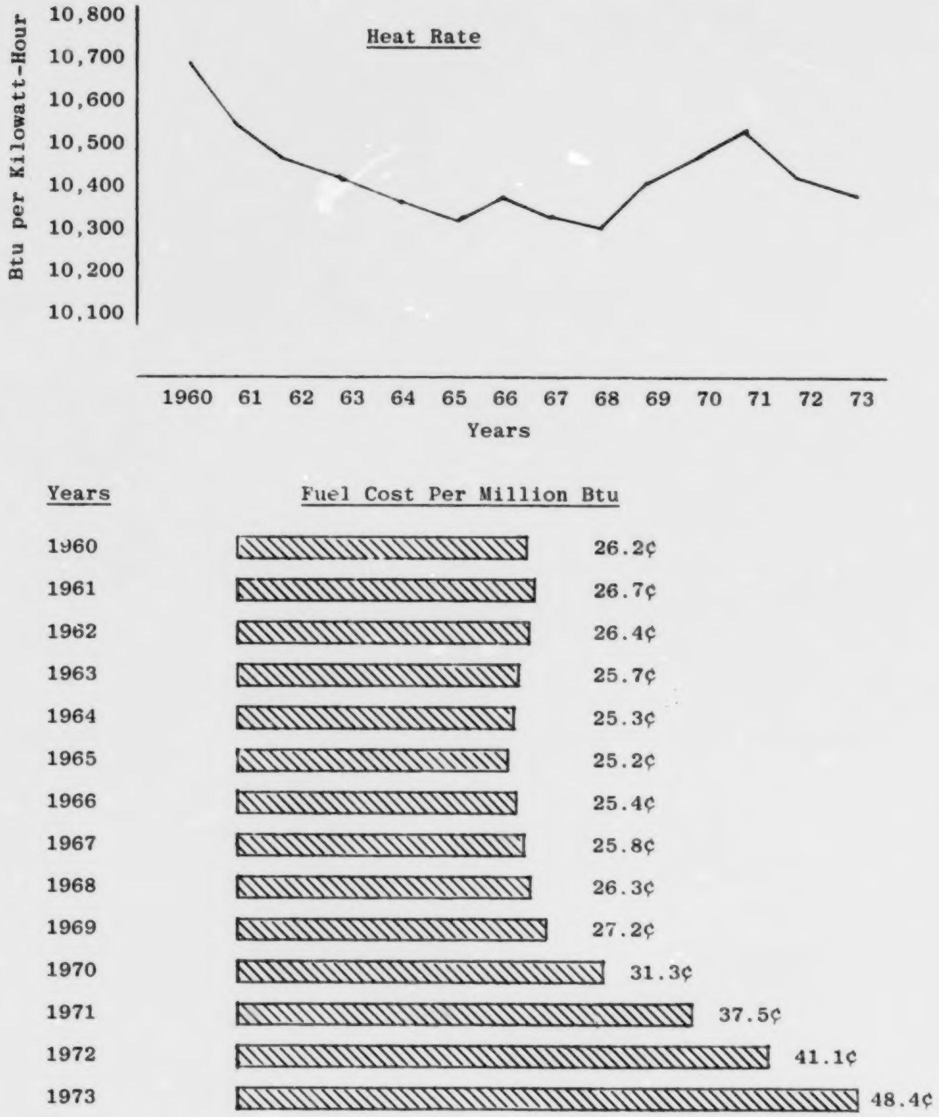
COST PER KILOWATT-HOUR - BOTH TOTAL AND MAJOR COMPONENTS - BOTTOMED OUT IN LATE 1960s, THEN CLIMBED STEADILY

		Operations & Maintenance Costs Per kWh				
Year	Total Cost Per kWh	Excluding Fuel	Fuel Only	Total	Interest Cost Per kWh	All Other Costs Per kWh
1960	16.3 mills	5.8 mills	2.9 mills	8.7 mills	1.2 mills	6.4 mills
1961	16.3	5.7	2.9	8.6	1.2	6.5
1962	16.0	5.6	2.9	8.5	1.2	6.3
1963	15.7	5.5	2.8	8.3	1.2	6.2
1964	15.4	5.4	2.8	8.2	1.1	6.1
1965	15.1	5.4	2.7	8.1	1.1	5.9
1966	14.9	5.3	2.8	8.1	1.1	5.7
1967	14.8	5.3	2.8	8.1	1.2	5.5
1968	14.8	5.1	2.9	8.0	1.3	5.5
1969	14.9	5.2	3.0	8.2	1.5	5.2
1970	15.5	5.4	3.5	8.9	1.8	4.8
1971	16.5	5.7	4.1	9.8	2.0	4.7
1972	17.2	6.0	4.4	10.4	2.1	4.7
1973	17.3	NA	NA	NA	NA	NA

Sources: FPC, EEI, TBS estimates

Exhibit 21

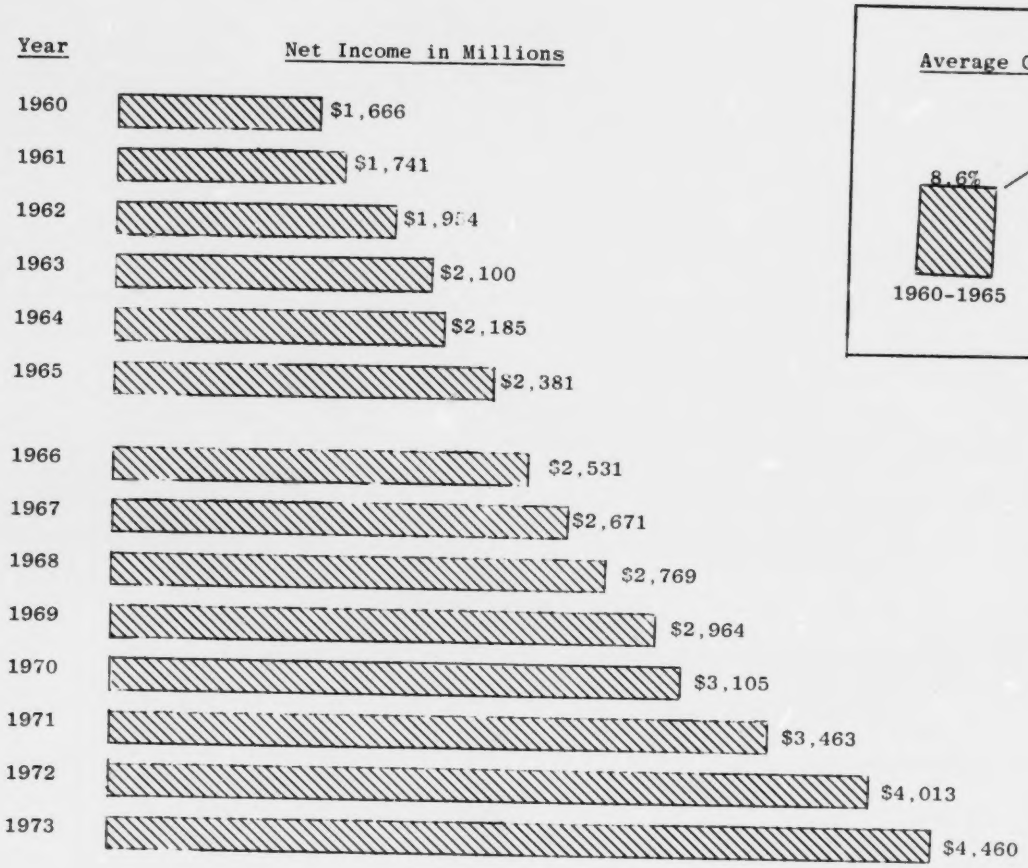
FUEL COST COMPONENTS BOTTOMED OUT IN MID-TO LATE-1960s AND INCREASED SINCE

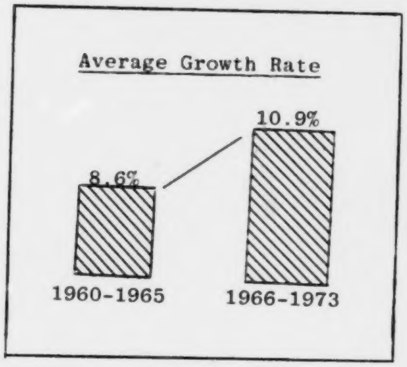


Source: EEI

Exhibit 22

NET INCOME FROM ELECTRIC OPERATIONS UP SUBSTANTIALLY SINCE MID-1960s



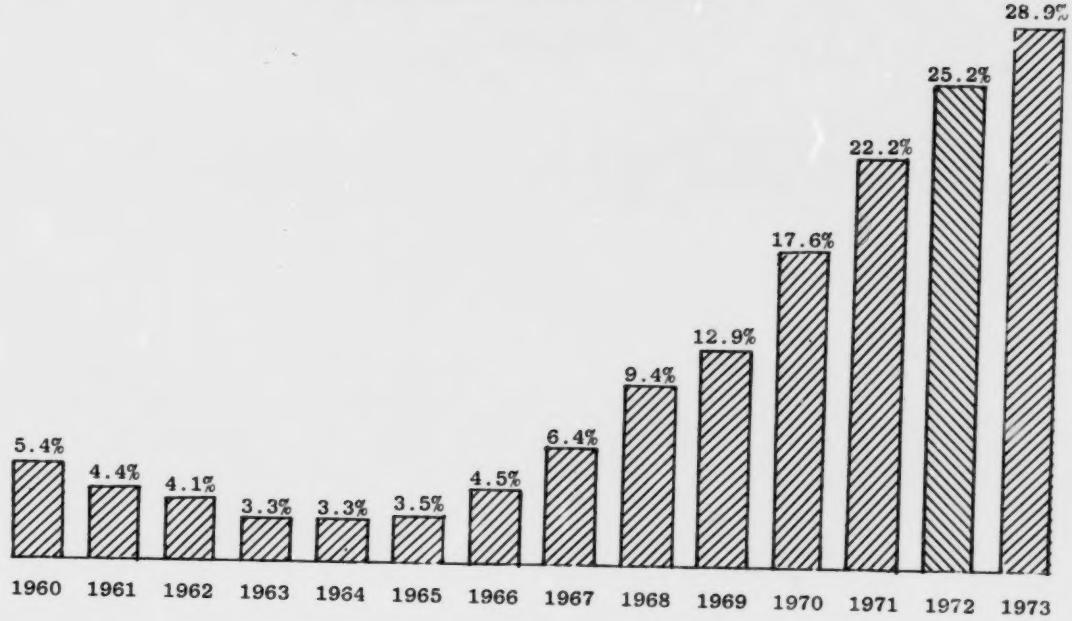


Source: FPC, TBS estimates

Exhibit 23

ALLOWANCE FOR FUNDS DURING CONSTRUCTION BECOMING AN INCREASINGLY LARGER PORTION OF TOTAL NET INCOME

AFDC As Percent of Net Income



Sources: FPC, TBS estimates

Exhibit 24

CAPITAL STRUCTURES RELATIVELY UNCHANGED OVER THE YEARS

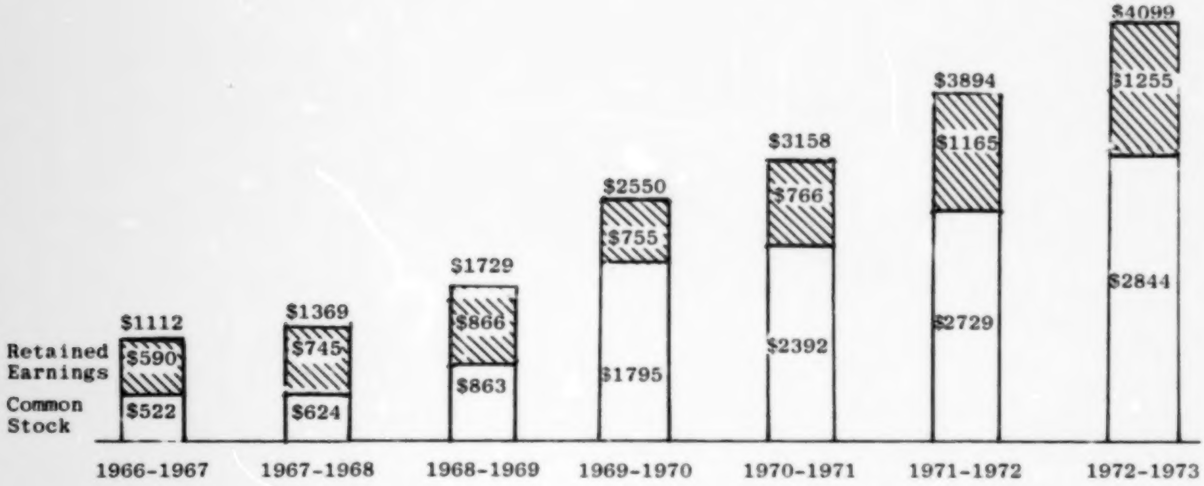
	Capital Structure Proportions		
Year	Debt	Preferred Stock	Common Equity
1960	52.8%	10.7%	36.5%
1965	51.5	9.5	39.0
1970	54.8	9.8	35.4
1973	52.3	12.1	35.6

Source: FPC

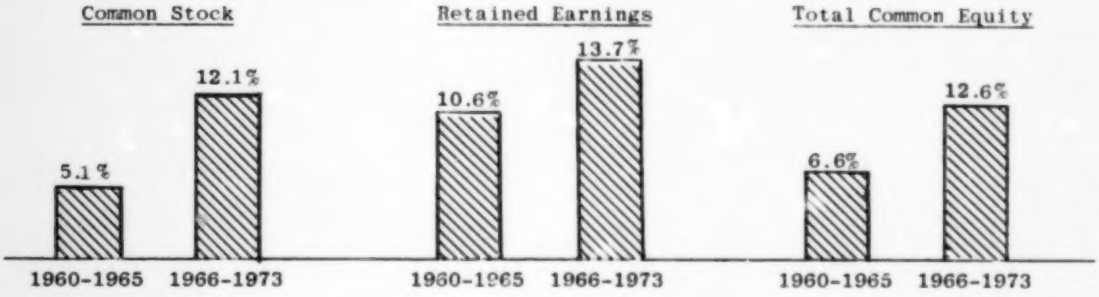
Exhibit 25

RATE OF GROWTH OF COMMON EQUITY UP SUBSTANTIALLY IN RECENT YEARS; COMMON STOCK GROWTH UP EVEN MORE

Growth in Common Equity in Millions



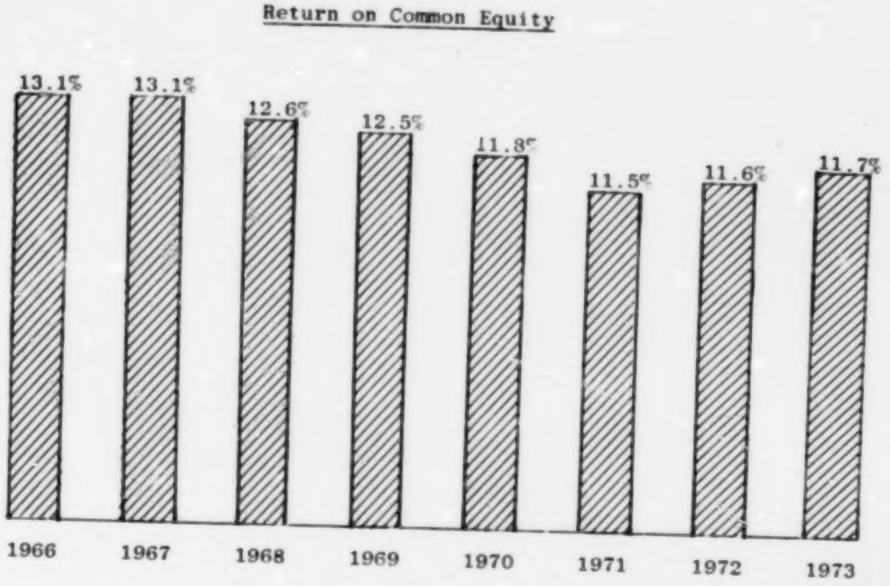
Average Annual Growth



Sources: FPC, TBS estimates

Exhibit 26

RETURN ON COMMON EQUITY DETERIORATED IN RECENT YEARS

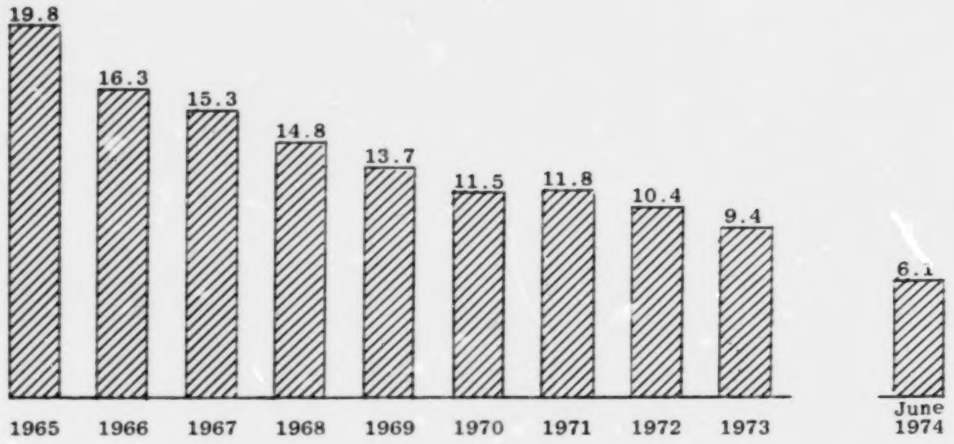


Sources: FPC, TBS estimates

Exhibit 27

PRICE EARNINGS RATIO OF COMMON STOCK DETERIORATED BADLY IN RECENT YEARS

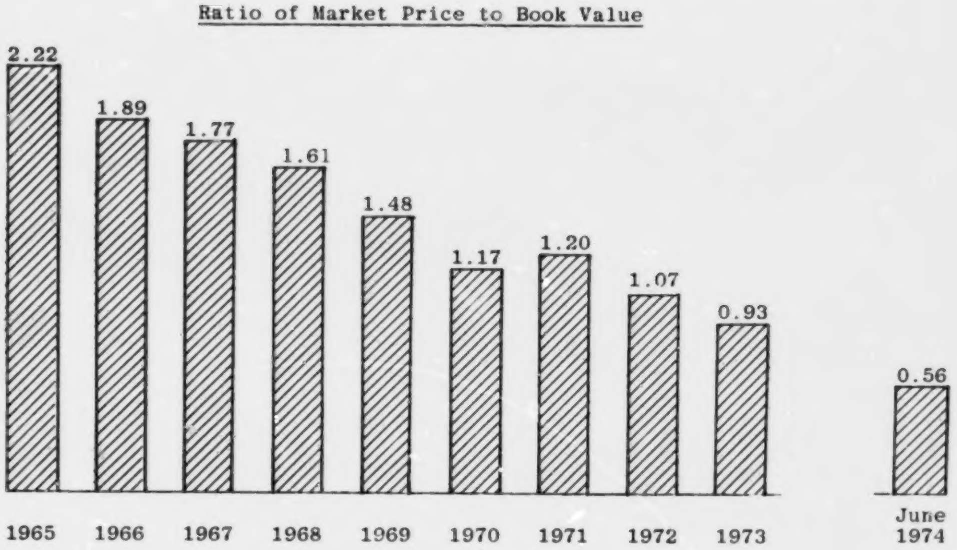
Price Earnings Ratio



Source: Moody's Public Utilities Manual

Exhibit 28

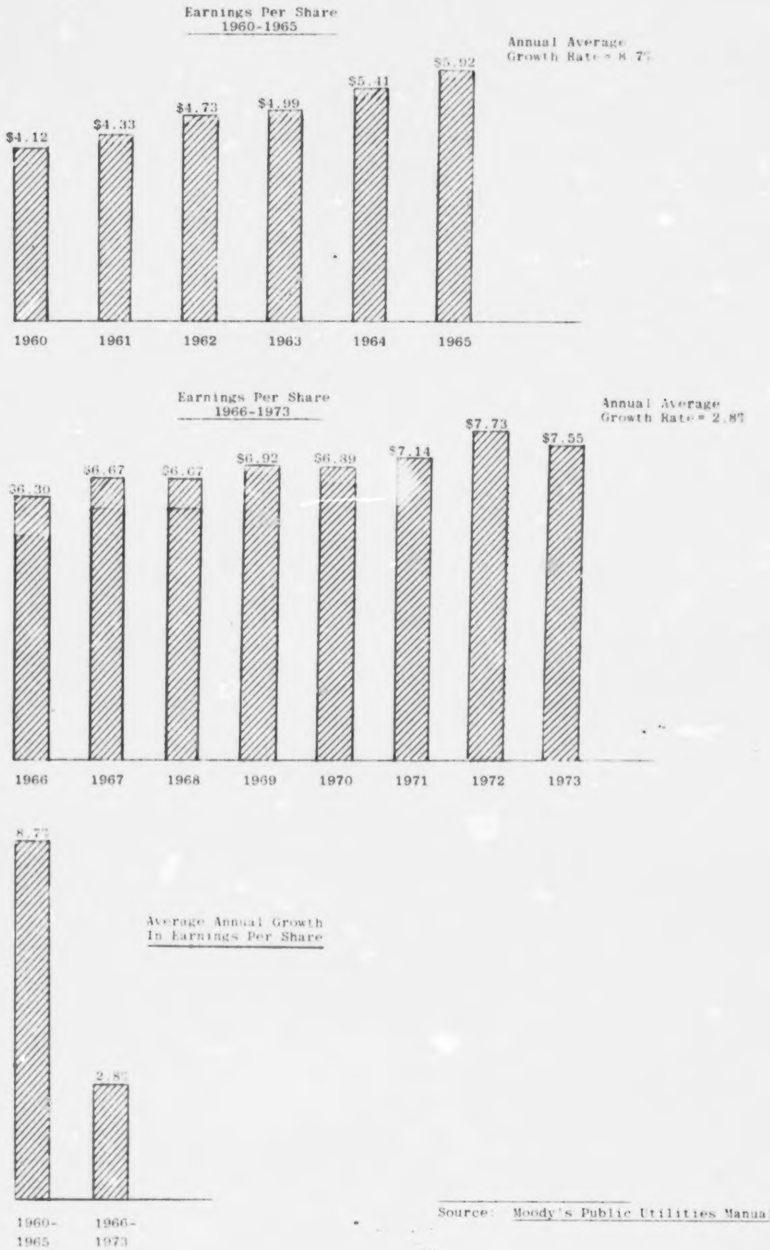
RATIO OF MARKET PRICE TO BOOK VALUE OF COMMON STOCK DETERIORATED STEADILY AND IS NOW LESS THAN ONE



Sources: Moody's Public Utilities Manual, TBS estimates

Exhibit 29

GROWTH RATE IN EARNINGS PER SHARE DETERIORATED
SHARPLY SINCE THE EARLY 1960s



Source: Moody's Public Utilities Manual

Exhibit 30

FACTORS INFLUENCING THE ELECTRIC UTILITY INDUSTRY'S RATE OF GROWTH IN GENERATION CAPACITY AND ELECTRIC ENERGY UNDER MODERATE GROWTH ASSUMPTIONS

1973 to 1990

(percent)

Year	Peak Load Growth Rate (1)	Capacity Reserve Margin (2)	Reserve Factor Growth Rate (3)	Generation Capacity Growth Rate (4)	Capacity Factor (5)	Capacity Factor Growth Rate (6)	Electric Energy Growth Rate (7)
1973	9.4%	20.0%	--	--	49.9%	--	--
1974	1.0	24.0	3.3%	4.3%	46.2	-7.4%	-3.4%
1975	4.0	26.0	1.6	5.7	44.9	-2.8	2.7
1976	6.5	25.0	-0.8	5.6	48.0	6.9	12.9
1977	6.5	24.0	-0.8	5.6	48.0	0.0	5.6
1978	6.5	23.0	-0.8	5.6	48.0	0.0	5.6
1979	6.5	22.0	-0.8	5.6	48.0	0.0	5.6
1980	6.5	21.0	-0.8	5.6	48.0	0.0	5.6
1981	6.0	20.0	-0.8	5.2	49.9	4.0	9.4
1982	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1983	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1984	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1985	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1986	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1987	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1988	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1989	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1990	5.5	20.0	0.0	5.5	49.9	0.0	5.5

Notes:

Column 1	NPS TAC-Finance assumption
Column 2	NPS TAC-Finance assumption
Column 3	Reserve factor = 1 + reserve margin
Column 4	Column 4 = (1 + Column 1)*(1 + Column 3) - 1
Column 5	NPS TAC-Finance assumption
Column 6	No explanation needed.
Column 7	Column 7 = (1 + Column 4)*(1 + Column 6) - 1 Column 7 has not been adjusted for leap years.

Source: TAC-Finance

Exhibit 30

FACTORS INFLUENCING THE ELECTRIC UTILITY INDUSTRY'S RATE OF GROWTH IN GENERATION CAPACITY AND ELECTRIC ENERGY UNDER MODERATE GROWTH ASSUMPTIONS

1973 to 1990

(percent)

Year	Peak Load Growth Rate (1)	Capacity Reserve Margin (2)	Reserve Factor Growth Rate (3)	Generation Capacity Growth Rate (4)	Capacity Factor (5)	Capacity Factor Growth Rate (6)	Electric Energy Growth Rate (7)
1973	9.4%	20.0%	--	--	49.9%	--	--
1974	1.0	24.0	3.3%	4.3%	46.2	-7.4%	-3.4%
1975	4.0	26.0	1.6	5.7	44.9	-2.8	2.7
1976	6.5	25.0	-0.8	5.6	48.0	6.9	12.9
1977	6.5	24.0	-0.8	5.6	48.0	0.0	5.6
1978	6.5	23.0	-0.8	5.6	48.0	0.0	5.6
1979	6.5	22.0	-0.8	5.6	48.0	0.0	5.6
1980	6.5	21.0	-0.8	5.6	48.0	0.0	5.6
1981	6.0	20.0	-0.8	5.2	49.9	4.0	9.4
1982	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1983	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1984	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1985	6.0	20.0	0.0	6.0	49.9	0.0	6.0
1986	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1987	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1988	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1989	5.5	20.0	0.0	5.5	49.9	0.0	5.5
1990	5.5	20.0	0.0	5.5	49.9	0.0	5.5

Notes:

Column 1	NPS TAC-Finance assumption
Column 2	NPS TAC-Finance assumption
Column 3	Reserve factor = 1 + reserve margin
Column 4	Column 4 = (1 + Column 1)*(1 + Column 3) - 1
Column 5	NPS TAC-Finance assumption
Column 6	No explanation needed.
Column 7	Column 7 = (1 + Column 4)*(1 + Column 6) - 1 Column 7 has not been adjusted for leap years.

Source: TAC-Finance

Exhibit 31

TOTAL ELECTRIC UTILITY INDUSTRY GENERATION CAPACITY ADDITIONS, RETIREMENTS, AND TOTALS BY PLANT TYPE AND TOTAL SALES TO ULTIMATE CONSUMERS UNDER MODERATE GROWTH ASSUMPTIONS

1973 to 1990

Year	Total Net Generation Capacity	Gross Capacity Additions	Generation from Non-Nuclear Plants			Generation from Nuclear Plants			Total Sales[1] to Ultimate Consumers
			Net Capacity	Gross Capacity Additions	Capacity Retirements	Net Capacity	Gross Capacity Additions	Capacity Retirements	
	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(billions of kWh)
1973	422.1	--	394.4	--	--	27.7	--	--	1,845.1
1974	440.5	20.0	406.8	14.0	1.6	33.7	6.0	--	1,782.8
1975	465.5	26.6	423.8	18.6	1.6	41.7	8.0	--	1,830.9
1976	491.8	29.3	438.4	17.6	3.0	53.4	11.7	--	2,067.9
1977	519.6	30.9	453.8	18.5	3.1	65.8	12.4	--	2,184.8
1978	549.0	32.5	470.2	19.5	3.2	78.8	13.0	--	2,308.4
1979	579.9	34.2	487.4	20.5	3.3	92.5	13.7	--	2,438.4
1980	612.5	36.0	505.6	21.6	3.4	106.9	14.4	--	2,575.4
1981	643.4	37.0	518.0	18.5	6.1	125.4	18.5	--	2,812.5
1982	682.1	44.9	534.3	22.5	6.2	147.8	22.4	--	2,981.6
1983	723.1	47.4	551.6	23.7	6.4	171.5	23.7	--	3,160.8
1984	766.4	50.0	569.9	25.0	6.6	196.5	25.0	--	3,350.1
1985	812.5	52.9	589.6	26.5	6.8	222.9	26.4	--	3,551.6
1986	857.2	51.8	603.2	20.7	7.1	254.0	31.1	--	3,747.0
1987	904.4	54.4	617.8	21.8	7.2	286.6	32.6	--	3,953.3
1988	954.2	57.2	633.3	22.9	7.4	320.9	34.3	--	4,171.0
1989	1,006.7	60.1	649.7	24.0	7.6	357.0	36.1	--	4,400.5
1990	1,062.1	63.2	667.2	25.3	7.8	394.9	37.9	--	4,642.7

[1] *No attempt was made to adjust these sales to account for leap years.*

Source: PTm

Exhibit 32

GENERATING CAPACITY COST GROWTH
(expressed in current dollars)

	1973	1977	1983	1990
Non-Nuclear Generating Capacity				
$ per kilowatt	$165.01	$235.62	$338.47	$446.26
% cost escalation	--	9.3%	6.2%	5.0%
Nuclear Generating Capacity				
$ per kilowatt	$226.47	$345.14	$497.87	$700.56
% cost escalation	--	11.1%	6.3%	5.0%

OTHER PLANT AND EQUIPMENT COST GROWTH
(expressed in current dollars)

	1973	1977	1983	1990
Nuclear Fuel				
$ per kilowatt	$ 43.16	$ 48.57	$ 63.22	$ 95.05
% cost escalation	--	3.0%	4.5%	6.0%
Transmission and Distribution Equipment				
$ per kilowatt	$208.37	$253.28	$339.42	$447.59
% cost escalation	--	5.0%	5.0%	5.0%

Source: TAC-Finance

Exhibit 33

SCHEDULE OF CONSTRUCTION WORK IN PROGRESS CASH PAYMENTS

Capital Expenditures for Non-Nuclear Generating Capacity (and related pollution control equipment) placed in service during Period T incurred by:

• Period T	100 Percent
• Period T-1	75 Percent
• Period T-2	50 Percent
• Period T-3	25 Percent

Capital Expenditures for Nuclear Generating Capacity (and related pollution control equipment) placed in service during Period T incurred by:

• Period T-1	100 Percent
• Period T-2	75 Percent
• Period T-3	50 Percent
• Period T-4	25 Percent

Capital Expenditures for Nuclear Fuel placed in service during Period T incurred by:

• Period T-1	100 Percent

Capital Expenditures incurred for Transmission and Distribution Equipment placed in-service during Period T incurred by:

• Period T	100 Percent
• Period T-1	50 Percent

Source: TAC-Finance

Exhibit 34

OPERATIONS AND MAINTENANCE COST GROWTH
(expressed in current dollars)

	1973	1977	1983	1990
Operations and Maintenance Expenses: Non-Nuclear Generating Capacity				
mills per kilowatt hour	9.5	15.3	22.3	31.4
% cost escalation	--	12.6%	6.5%	5.0%
Operations and Maintenance Expenses: Nuclear Generating Capacity (excluding fuel)				
mills per kilowatt hour	4.2	5.1	6.8	9.6
% cost escalation	--	5.0%	5.0%	5.0%

Source: TAC Finance

Exhibit 35

ECONOMIC AND FINANCIAL PROJECTIONS OF BASELINE CONDITIONS WITH MODERATE GROWTH ASSUMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 17.9	$ 28.3	$ 39.1
Total since 1973	--	60.3	203.2	441.4
Construction Work in Progress				
End of year	$ 19.6	$26.5	$ 43.8	$ 62.2
External Financing				
Total for year	$ 7.6	$ 10.9	$ 17.8	$ 23.6
Total since 1973	--	35.8	126.3	272.6
Operating Revenues				
Total for year	$ 39.5	$ 52.5	$ 74.7	$ 104.1
Total since 1973	--	188.8	579.5	1,218.0
Operations & Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.4	$ 38.0	$ 49.5
Total since 1973	--	92.0	292.5	603.7
Consumer Charges (mills/kWh)				
Average for year	21.4	24.0	23.6	22.4

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 36

FACTORS INFLUENCING THE ELECTRIC UTILITY INDUSTRY'S RATE OF GROWTH IN GENERATION CAPACITY AND ELECTRIC ENERGY UNDER HISTORIC GROWTH ASSUMPTIONS

1973 to 1990

(percent)

Year	Peak Load Growth Rate (1)	Capacity Reserve Margin (2)	Reserve Factor Growth Rate (3)	Generation Capacity Growth Rate (4)	Capacity Factor (5)	Capacity Factor Growth Rate (6)	Electric Energy Growth Rate (7)
1973	9.4%	20.0%	--	--	49.9%	--	--
1974	3.0	26.0	5.0%	8.2%	46.2	-7.4%	0.2%
1975	5.0	28.0	1.6	6.7	44.9	-2.8	3.7
1976	7.2	26.7	-1.0	6.1	47.4	5.6	12.0
1977	7.2	25.3	-1.1	6.0	47.4	0.0	6.0
1978	7.2	24.0	-1.0	6.1	47.4	0.0	6.1
1979	7.2	22.7	-1.0	6.1	47.4	0.0	6.1
1980	7.2	21.3	-1.1	6.0	47.4	0.0	6.0
1981	6.7	20.0	-1.1	6.0	49.9	5.3	11.6
1982	6.7	20.0	0.0	6.7	49.9	0.0	6.7
1983	6.7	20.0	0.0	6.7	49.9	0.0	6.7
1984	6.7	20.0	0.0	6.7	49.9	0.0	6.7
1985	6.7	20.0	0.0	6.7	49.9	0.0	6.7
1986	6.6	20.0	0.0	6.6	49.9	0.0	6.6
1987	6.6	20.0	0.0	6.6	49.9	0.0	6.6
1988	6.6	20.0	0.0	6.6	49.9	0.0	6.6
1989	6.6	20.0	0.0	6.6	49.9	0.0	6.6
1990	6.6	20.0	0.0	6.6	49.9	0.0	6.6

Notes:

Column 1 NPS TAC-Finance assumption
Column 2 NPS TAC-Finance assumption
Column 3 Reserve factor = 1 + reserve margin
Column 4 Column 4 = (1 + Column 1)*(1 + Column 3) - 1
Column 5 NPS TAC-Finance assumption
Column 6 No explanation needed.
Column 7 Column 7 = (1 + Column 4)*(1 + Column 6) - 1
Column 7 has not been adjusted for leap years.

Source: TAC-Finance

Exhibit 37

TOTAL ELECTRIC UTILITY INDUSTRY GENERATION CAPACITY ADDITIONS, RETIREMENTS, AND TOTALS BY PLANT TYPE AND TOTAL SALES TO ULTIMATE CONSUMERS UNDER HISTORIC GROWTH ASSUMPTIONS

1973 to 1990

Year	Total Net Generation Capacity	Gross Capacity Additions	Generation from Non-Nuclear Plants			Generation from Nuclear Plants			Total Sales Ultimate Consumers
			Net Capacity	Gross Capacity Additions	Capacity Retirements	Net Capacity	Gross Capacity Additions	Capacity Retirements	
	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(millions of kW)	(billions of kWh)
1973	422.1	--	394.4	--	--	27.7	--	--	1,845.1
1974	456.5	36.0	418.0	25.2	1.6	38.5	10.8	--	1,847.5
1975	487.0	32.1	438.9	22.5	1.7	48.1	9.6	--	1,915.5
1976	516.7	32.8	455.5	19.7	3.1	61.2	13.1	--	2,145.5
1977	547.8	34.3	472.9	20.6	3.2	74.9	13.7	--	2,274.6
1978	581.2	36.7	491.6	22.0	3.3	89.6	14.7	--	2,413.3
1979	616.5	38.8	511.4	23.3	3.4	105.1	15.5	--	2,559.9
1980	653.4	40.4	532.1	24.2	3.6	121.3	16.2	--	2,713.1
1981	689.7	42.7	547.1	21.4	6.4	142.6	21.3	--	3,014.8
1982	735.9	52.8	566.9	26.4	6.6	169.0	26.4	--	3,216.8
1983	785.2	56.1	588.2	28.1	6.8	197.0	28.0	--	3,432.3
1984	837.8	59.7	611.0	29.9	7.1	226.8	29.8	--	3,662.2
1985	894.0	63.5	635.4	31.7	7.3	258.6	31.8	--	3,907.9
1986	953.0	66.6	654.4	26.6	7.6	298.6	40.0	--	4,165.8
1987	1,015.8	70.7	674.8	28.3	7.9	341.0	42.4	--	4,440.3
1988	1,082.8	75.1	696.7	30.0	8.1	386.1	45.1	--	4,733.2
1989	1,154.3	79.8	720.3	31.9	8.4	434.0	47.9	--	5,045.7
1990	1,230.4	84.8	745.5	33.9	8.6	484.9	50.9	--	5,378.4

Source: PTm

Exhibit 38

ECONOMIC AND FINANCIAL PROJECTIONS OF BASELINE CONDITIONS WITH HISTORIC GROWTH, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 18.3	$ 20.1	$ 34.3	$ 53.4
Total since 1973	--	72.9	241.2	555.2
Construction Work in Progress				
End of year	$ 24.0	$ 29.9	$ 53.5	$ 85.0
External Financing				
Total for year	$ 11.8	$ 12.4	$ 22.3	$ 33.7
Total since 1973	--	45.4	154.4	355.6
Operating Revenues				
Total for year	$ 39.5	$ 55.5	$ 81.9	$122.8
Total since 1973	--	198.4	619.4	1,348.5
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 27.3	$ 40.7	$ 56.1
Total since 1973	--	95.0	306.6	650.8
Consumer Charges (mills/kWh)				
Average for year	21.4	24.4	23.9	22.8

---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 39

ECONOMIC AND FINANCIAL IMPACT OF REDUCED GROWTH - 1977

(dollar figures in billions of 1974 dollars)

	Historic Growth Conditions	Impact of Reduced Growth	Baseline Conditions
Capital Expenditures			
Total for year	$20.1	- 2.2	$17.9
Total since 1973	72.9	-12.6	60.3
Construction Work in Progress			
End of year	$29.9	- 3.4	$26.5
External Financing			
Total for year	$12.4	- 1.5	$10.9
Total since 1973	45.4	- 9.6	35.8
Operating Revenues			
Total for year	$55.5	- 3.0	$52.5
Total since 1973	198.4	- 9.6	188.8
Operations and Maintenance Expenses[1]			
Total for year	$27.3	- 0.9	$26.4
Total since 1973	95.0	- 3.0	92.0
Consumer Charges (Mills/kWh)			
Average for year	24.4	- 0.4	24.0

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 40

ECONOMIC AND FINANCIAL IMPACT OF REDUCED GROWTH - 1983

(dollar figures in billions of 1974 dollars)

	Historic Growth Conditions	Impact of Reduced Growth	Baseline Conditions
Capital Expenditures			
Total for year	$ 34.3	- 6.0	$ 28.3
Total since 1973	241.2	-38.0	203.2
Construction Work in Progress			
End of year	$ 53.5	- 9.7	$ 43.8
External Financing			
Total for year	$ 22.3	- 4.5	$ 17.8
Total since 1973	154.4	-28.1	126.3
Operating Revenues			
Total for year	$ 81.9	- 7.2	$ 74.7
Total since 1973	619.4	-39.9	579.5
Operations and Maintenance Expenses[1]			
Total for year	$ 40.7	- 2.7	$ 38.0
Total since 1973	306.6	-14.1	292.5
Consumer Charges (Mills/kWh)			
Average for year	23.9	- 0.3	23.6

[1] *Excludes Nuclear Fuel*

Source: PTm

Exhibit 41

ECONOMIC AND FINANCIAL IMPACT OF REDUCED GROWTH - 1990

(dollar figures in billions of 1974 dollars)

	Historic Growth Conditions	Impact of Reduced Growth	Baseline Conditions
Capital Expenditures			
Total for year	$ 53.4	- 14.3	$ 39.1
Total since 1973	555.2	-113.8	441.4
Construction Work in Progress			
End of year	$ 85.0	- 22.8	$ 62.2
External Financing			
Total for year	$ 33.7	- 10.1	$ 23.6
Total since 1973	355.6	- 83.0	272.6
Operating Revenues			
Total for year	$122.8	- 18.7	$104.1
Total since 1973	1,348.5	-130.5	1,218.0
Operations and Maintenance Expenses[1]			
Total for year	$ 56.1	- 6.6	$ 49.5
Total since 1973	650.8	- 47.1	603.7
Consumer Charges (Mills/kWh)			
Average for year	22.8	- 0.4	22.4

[1] *Excludes Nuclear Fuel*

Source: PTm

Exhibit 42

CAPITAL COST GROWTH - THERMAL GUIDELINES
(expressed in current dollars)

	1973	1977	1983	1990
Non-Nuclear Generating Capacity: Retrofitted Units				
$ per kilowatt	$21.58	$26.89	$36.71	$51.66
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: New Units				
$ per kilowatt	$ 5.17	$ 6.44	$ 8.79	$12.36
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Retrofitted Units				
$ per kilowatt	$26.01	$32.58	$44.67	$62.86
% cost escalation	--	5.8%	5.4%	5.0%
Nuclear Generating Capacity: New Units				
$ per kilowatt	$ 4.06	$ 5.09	$ 6.98	$ 9.82
% cost escalation	--	5.8%	5.4%	5.0%

Source: Burns and Roe, Sargent and Lundy

Exhibit 43

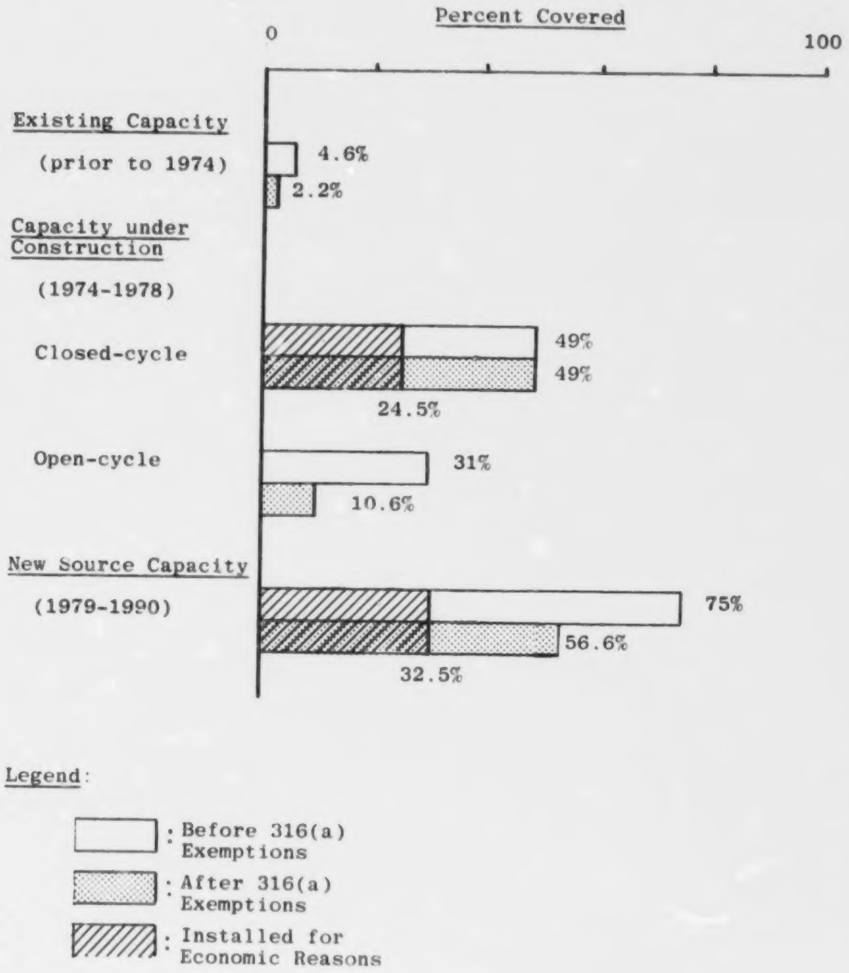
ANNUAL OPERATING COST GROWTH - THERMAL GUIDELINES
(expressed in current dollars)

	1973	1977	1983	1990
All Generating Capacity: Retrofitted Units				
$ per kilowatt	$45.32	$72.95	$106.38	$149.69
% cost escalation	--	12.6%	6.5%	5.0%
Non-Nuclear Generating Capacity: New Units				
$ per kilowatt	$45.34	$72.99	$106.44	$149.77
% cost escalation	--	12.6%	6.5%	5.0%
Nuclear Generating Capacity: New Units				
$ per kilowatt	$24.28	$29.51	$39.54	$55.64
% cost escalation	--	5.0%	5.0%	5.0%

Source: EPA estimates

Exhibit 44

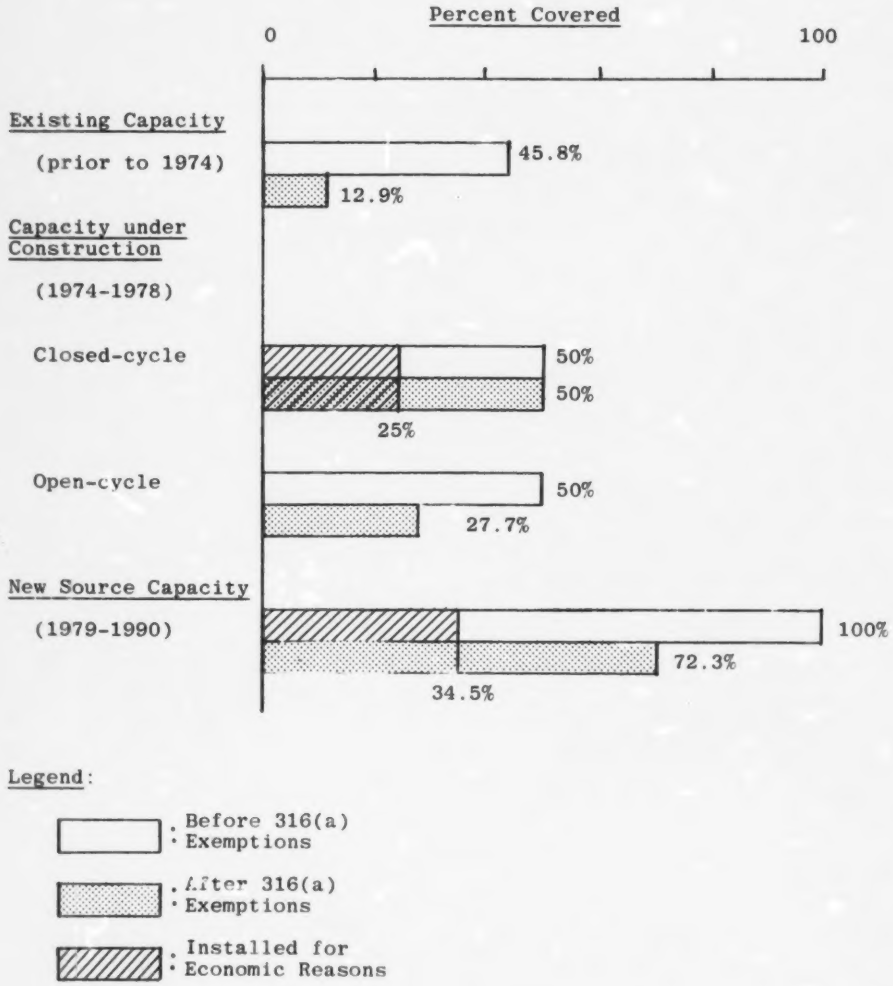
NON-NUCLEAR CAPACITY COVERAGE BY IN SERVICE YEAR



Source: ERCO, EPA estimates

Exhibit 45

NUCLEAR CAPACITY COVERAGE BY IN SERVICE YEAR



Source: ERCO, EPA estimates

Exhibit 46

INSTALLATION SCHEDULE FOR RETROFITTED UNITS
(percentage of units)

	1981	1982	1983	Total
Non-Nuclear Generating Capacity: Placed in Service Prior to 1974				
Before 316(a) Exemptions	4.6%	-	-	4.6%
After 316(a) Exemptions	2.2%	-	-	2.2%
Non-Nuclear Generating Capacity: Placed in Service 1974-1978				
Before 316(a) Exemptions	21.3%	6.3%	3.4%	31.0%
After 316(a) Exemptions	7.4%	2.2%	1.0%	10.6%
Nuclear Generating Capacity: Placed in Service Prior to 1974				
Before 316(a) Exemptions	45.8%	-	-	45.8%
After 316(a) Exemptions	12.9%	-	-	12.9%
Nuclear Generating Capacity: Placed in Service 1974-1978				
Before 316(a) Exemptions	49.6%	0.4%	-	50.0%
After 316(a) Exemptions	27.7%	-	-	27.7%

Source: ERCO, EPA estimates

Exhibit 47

ECONOMIC AND FINANCIAL PROJECTIONS WITH THERMAL POLLUTION CONTROL EQUIPMENT FOR ECONOMIC REASONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.0	$ 28.5	$ 39.5
Total since 1973	--	60.9	205.1	445.5
Construction Work in Progress				
End of year	$ 19.6	$ 26.7	$ 44.3	$ 62.9
External Financing				
Total for year	$ 7.6	$ 11.0	$ 18.0	$ 23.8
Total since 1973	--	36.3	127.8	275.5
Operating Revenues				
Total for year	$ 39.5	$ 52.6	$ 75.1	$ 104.9
Total since 1973	--	189.0	581.2	1,223.5
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.1	$ 49.8
Total since 1973	--	92.1	293.2	606.1
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	23.7	22.6
Capacity Losses (millions of kW)				
Total since 1973	--	0.8	3.0	7.0
Energy Penalty (Quads)				
Total for year	--	0.1	0.2	0.4

---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 48

ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL THERMAL GUIDELINES BEFORE SECTION 316(a) EXEMPTIONS FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.5	$ 29.0	$ 40.0
Total since 1973	--	62.4	211.2	455.2
Construction Work in Progress				
End of year	$ 19.6	$ 27.9	$ 45.2	$ 64.2
External Financing				
Total for year	$ 7.6	$ 11.5	$ 18.3	$ 24.2
Total since 1973	--	37.6	132.6	282.3
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 76.2	$ 106.5
Total since 1973	--	189.3	585.3	1,237.3
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.5	$ 50.5
Total since 1973	--	92.2	294.7	611.2
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	24.1	22.9
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	9.8	20.2
Energy Penalty (Quads)				
Total for year	--	0.1	0.6	1.1

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 49

ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL THERMAL GUIDELINES AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.3	$ 28.8	$ 39.8
Total since 1973	--	61.8	208.3	450.8
Construction Work in Progress				
End of year	$ 19.6	$ 27.4	$ 44.8	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 18.2	$ 24.0
Total since 1973	--	37.1	130.3	279.2
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 75.7	$ 105.7
Total since 1973	--	189.2	583.6	1,231.2
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.3	$ 50.2
Total since 1973	--	92.2	294.1	609.1
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	23.9	22.8
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	7.0	14.6
Energy Penalty (Quads)				
Total for year	--	0.1	0.4	0.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 50

ECONOMIC AND FINANCIAL IMPACT OF THERMAL POLLUTION CONTROL EQUIPMENT FOR ECONOMIC REASONS - 1977

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Economic Reasons	Projections With Thermal Equipment For Economic Reasons
Capital Expenditures			
Total for year	$ 17.9	+0.1	$ 18.0
Total since 1973	60.3	+0.6	60.9
Construction Work in Progress			
End of year	$ 26.5	+0.2	$ 26.7
External Financing			
Total for year	$ 10.9	+0.1	$ 11.0
Total since 1973	35.8	+0.5	36.3
Operating Revenues			
Total for year	$ 52.5	+0.1	$ 52.6
Total since 1973	188.8	+0.2	189.0
Operations and Maintenance Expenses[1]			
Total for year	$ 26.4	+0.1	$ 26.5
Total since 1973	92.0	+0.1	92.1
Consumer Charges (mills/kWh)			
Average for year	24.0	+0.1	24.1
Capacity Losses (millions of kW)			
Total since 1973	--	+0.8	0.8
Energy Penalty (Quads)			
Total for year	--	+0.1	0.1

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 51

ECONOMIC AND FINANCIAL IMPACT OF THERMAL POLLUTION CONTROL EQUIPMENT FOR ECONOMIC REASONS - 1983

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Economic Reasons	Projections With Thermal Equipment for Economic Reasons
Capital Expenditures			
Total for year	$ 28.3	+0.2	$ 28.5
Total since 1973	203.2	+1.9	205.1
Construction Work in Progress			
End of year	$ 43.8	+0.5	$ 44.3
External Financing			
Total for year	$ 17.8	+0.2	$ 18.0
Total since 1973	126.3	+1.5	127.8
Operating Revenues			
Total for year	$ 74.7	+0.4	$ 75.1
Total since 1973	579.5	+1.7	581.2
Operations and Maintenance Expenses[1]			
Total for year	$ 38.0	+0.1	$ 38.1
Total since 1973	292.5	+0.7	293.2
Consumer Charges (mills/kWh)			
Average for year	23.6	+0.1	23.7
Capacity Losses (millions of kW)			
Total since 1973	--	+3.0	3.0
Energy Penalty (Quads)			
Total for year	--	+0.2	0.2

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 52

ECONOMIC AND FINANCIAL IMPACT OF THERMAL POLLUTION CONTROL EQUIPMENT FOR ECONOMIC REASONS - 1990

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Economic Reasons	Projections With Thermal Equipment For Economic Reasons
Capital Expenditures			
Total for year	$ 39.1	+0.4	$ 39.5
Total since 1973	441.4	+4.1	445.5
Construction Work in Progress			
End of year	$ 62.2	+0.7	$ 62.9
External Financing			
Total for year	$ 23.6	+0.2	$ 23.8
Total since 1973	272.6	+2.9	275.5
Operating Revenues			
Total for year	$ 104.1	+0.8	$ 104.9
Total since 1973	1,218.0	+5.5	1,223.5
Operations and Maintenance Expenses[1]			
Total for year	$ 49.5	+0.3	$ 49.8
Total since 1973	603.7	+2.4	606.1
Consumer Charges (mills/kWh)			
Average for year	22.4	+0.2	22.6
Capacity Losses (millions of kW)			
Total since 1973	--	+7.0	7.0
Energy Penalty (Quads)			
Total for year	--	+0.4	0.4

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 53.

ECONOMIC AND FINANCIAL IMPACT OF FINAL THERMAL GUIDELINES BEFORE SECTION 316(a) EXEMPTIONS - 1977

(dollar figures in billions of 1974 dollars)

	Projections With Thermal Equipment for Economic Reasons	Impact of Thermal Requirements Before 316(a)	Projections With Thermal Requirements Before 316(a)
Capital Expenditures			
Total for year	$ 18.0	+0.5	$ 18.5
Total since 1973	60.9	+1.5	62.4
Construction Work in Progress			
End of year	$ 26.7	+1.2	$ 27.9
External Financing			
Total for year	$ 11.0	+0.5	$ 11.5
Total since 1973	36.3	+1.3	37.6
Operating Revenues			
Total for year	$ 52.6	+0.1	$ 52.7
Total since 1973	189.0	+0.3	189.3
Operations and Maintenance Expenses[1]			
Total for year	$ 26.5	+0.0	$ 26.5
Total since 1973	92.1	+0.1	92.2
Consumer Charges (mills/kWh)			
Average for year	24.1	+0.0	24.1
Capacity Losses (millions of kW)			
Total since 1973	0.8	+0.8	1.6
Energy Penalty (Quads)			
Total for year	0.1	+0.0	0.1

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 54

ECONOMIC AND FINANCIAL IMPACT OF FINAL THERMAL GUIDELINES BEFORE SECTION 316(a) EXEMPTIONS - 1983

(dollar figures in billions of 1974 dollars)

	Projections With Thermal Equipment for Economic Reasons	Impact of Thermal Requirements Before 316(a)	Projections With Thermal Requirements Before 316(a)
Capital Expenditures			
Total for year	$ 28.5	+0.5	$ 29.0
Total since 1973	205.1	+6.1	211.2
Construction Work in Progress			
End of year	$ 44.3	+0.9	$ 45.2
External Financing			
Total for year	$ 18.0	+0.3	$ 18.3
Total since 1973	127.8	+4.8	132.6
Operating Revenues			
Total for year	$ 75.1	+1.1	$ 76.2
Total since 1973	$581.2	+4.1	585.3
Operations and Maintenance Expenses[1]			
Total for year	$ 38.1	+0.4	$ 38.5
Total since 1973	293.2	+1.5	294.7
Consumer Charges (mills/kWh)			
Average for year	23.7	+0.4	24.1
Capacity Losses (millions of kW)			
Total since 1973	3.0	+6.8	9.8
Energy Penalty (Quads)			
Total for year	0.2	+0.4	0.6

---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 55

ECONOMIC AND FINANCIAL IMPACT OF FINAL THERMAL GUIDELINES BEFORE SECTION 316(a) EXEMPTIONS - 1990

(dollar figures in billions of 1974 dollars)

	Projections With Thermal Equipment for Economic Reasons	Impact of Thermal Requirements Before 316(a)	Projections With Thermal Requirements Before 316(a)
Capital Expenditures			
Total for year	$ 39.5	+0.5	$ 40.0
Total since 1973	445.5	+9.7	455.2
Construction Work in Progress			
End of year	$ 62.9	+1.3	$ 64.2
External Financing			
Total for year	$ 23.8	+0.4	$ 24.2
Total since 1973	275.5	+6.8	282.3
Operating Revenues			
Total for year	$ 104.9	+1.6	$ 106.5
Total since 1973	1,223.5	+14.0	1,237.5
Operations and Maintenance Expenses[1]			
Total for year	$ 49.8	+0.7	$ 50.5
Total since 1973	606.1	+5.1	611.2
Consumer Charges (mills/kWh)			
Average for year	22.6	+0.3	22.9
Capacity Losses (millions of kW)			
Total since 1973	7.0	+13.2	20.2
Energy Penalty (Quads)			
Total for year	0.4	+0.7	1.1

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 56

ECONOMIC AND FINANCIAL IMPACT OF FINAL THERMAL GUIDELINES AFTER SECTION 316(a) EXEMPTIONS - 1977

	Projections With Thermal Equipment for Economic Reasons	Impact of Thermal Requirements After 316(a)	Projections With Thermal Requirements After 316(a)
Capital Expenditures			
Total for year	$ 18.0	+ 0.3	$ 18.3
Total since 1973	60.9	+ 0.9	61.8
Construction Work in Progress			
End of year	$ 26.7	+ 0.7	$ 27.4
External Financing			
Total for year	$ 11.0	+ 0.2	$ 11.2
Total since 1973	36.3	+ 0.8	37.1
Operating Revenues			
Total for year	$ 52.6	+ 0.1	$ 52.7
Total since 1973	189.0	+ 0.2	189.2
Operations and Maintenance Expenses[1]			
Total for year	$ 26.5	+ 0.0	$ 26.5
Total since 1973	92.1	+ 0.1	92.2
Consumer Charges (mills/kWh)			
Average for year	24.1	+ 0.0	24.1
Capacity Losses (millions of kW)			
Total since 1973	0.8	+ 0.8	1.6
Energy Penalty (Quads)			
Total for year	0.1	+ 0.0	0.1

---

[1] *Excludes nuclear fuel.*

Source: PTm

Exhibit 57

ECONOMIC AND FINANCIAL IMPACT OF FINAL THERMAL GUIDELINES AFTER SECTION 316(a) EXEMPTIONS - 1983

	Projections With Thermal Equipment for Economic Reasons	Impact Of Thermal Requirements After 316(a)	Projections With Thermal Requirements After 316(a)
Capital Expenditures			
Total for year	$ 28.5	+ 0.3	$ 28.8
Total since 1973	205.1	+ 3.2	208.3
Construction Work in Progress			
End of year	$ 44.3	+ 0.5	$ 44.8
External Financing			
Total for year	$ 18.0	+ 0.2	$ 18.2
Total si[illegible] 1973	127.8	+ 2.5	130.3
Operating Revenues			
Total for year	$ 75.1	+ 0.6	$ 75.7
Total since 1973	581.2	+ 2.4	583.6
Operations and Maintenance Expenses[1]			
Total for year	$ 38.1	+ 0.2	38.3
Total since 1973	293.2	+ 0.9	294.1
Consumer Charges (mills/kWh)			
Average for year	23.7	+ 0.2	23.9
Capacity Losses (millions of kW)			
Total since 1973	3.0	+ 4.0	7.0
Energy Penalty (Quads)			
Total for year	0.2	+ 0.2	0.4

[1] *Excludes nuclear fuel.*

Source: PTm

Exhibit 58

ECONOMIC AND FINANCIAL IMPACT OF FINAL THERMAL GUIDELINES AFTER SECTION 316 (a) EXEMPTIONS -1990

	Projections With Thermal Equipment for Economic Reasons	Impact Of Thermal Requirements After 316(a)	Projections With Thermal Requirements After 316(a)
Capital Expenditures			
Total for year	$ 39.5	+ 0.3	$ 39.8
Total since 1973	445.5	+ 5.3	450.8
Construction Work in Progress			
End of year	$ 62.9	+ 0.8	$ 63.7
External Financing			
Total for year	23.8	+ 0.2	$ 24.0
Total since 1973	275.5	+ 3.7	279.2
Operating Revenues			
Total for year	$ 104.9	+ 0.8	$105.7
Total since 1973	$1,223.5	+ 7.7	$1,231.2
Operations and Maintenance Expenses[1]			
Total for year	$ 49.8	+ 0.4	$ 50.2
Total since 1973	606.1	+ 3.0	609.1
Consumer Charges (mills/kWh)			
Average for year	22.6	+ 0.2	22.8
Capacity Losses (millions of kW)			
Total since 1973	7.0	+ 7.6	14.6
Energy Penalty (Quads)			
Total for year	0.4	+ 0.4	0.8

[1] *Excludes nuclear fuel.*

Source: PTm

Exhibit 59

CAPITAL COST GROWTH - 1977 CHEMICAL GUIDELINES
(expressed in current dollars)

	1973	1977	1983	1990
Non-Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 1.80	$ 2.24	$ 3.05	$ 4.30
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 1.36	$ 1.70	$ 2.32	$ 3.26
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 0.61	$ 0.77	$ 1.05	$ 1.48
% cost escalation	--	5.8%	5.4%	5.4%
Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.61	$ 0.77	$ 1.05	$ 1.48
% cost escalation	--	5.8%	5.4%	5.4%

Source: EPA estimates

Exhibit 60

CAPITAL COST GROWTH - 1983 CHEMICAL GUIDELINES[1]

(expressed in current dollars)

	1973	1977	1983	1990
Non-Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 0.61	$ 0.76	$ 1.04	$ 1.47
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.55	$ 0.68	$ 0.93	$ 1.31
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1979-1990				
$ per kilowatt	$ 1.72	$ 2.15	$ 2.93	$ 4.12
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Placed In Service 1979-1990				
$ per kilowatt	$ 0.51	$ 0.64	$ 0.87	$ 1.23
% cost escalation	--	5.8%	5.4%	5.0%

[1] *These capital expenditures are in addition to those required to meet the 1977 guidelines.*

Source: EPA estimates

Exhibit 61

ANNUAL OPERATING COST GROWTH - 1977 CHEMICAL GUIDELINES
(expressed in current dollars)

	1973	1977	1983	1990
Non-Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 0.57	$ 0.69	$ 0.92	$ 1.30
% cost escalation	--	5.0%	5.0%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.26	$ 0.32	$ 0.43	$ 0.61
% cost escalation	--	5.0%	5.0%	5.0%
Nuclear Generating Capacity: Placed In Service prior to 1974				
$ per kilowatt	$ 0.21	$ 0.26	$ 0.34	$ 0.48
% cost escalation	--	5.0%	5.0%	5.0%
Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.21	$ 0.26	$ 0.34	$ 0.48
% cost escalation	--	5.0%	5.0%	5.0%

Source: EPA estimates

Exhibit 62

ANNUAL OPERATING COST GROWTH - 1983 CHEMICAL GUIDELINES[1]
(expressed in current dollars)

	1973	1977	1983	1990
Non-Nuclear Generating Capacity: Placed in Service Prior to 1974				
$ per kilowatt	$ 0.06	$ 0.08	$ 0.10	$ 0.14
% cost escalation	--	5.0%	5.0%	5.0%
Non-Nuclear Generating Capacity: Placed in Service 1974-1978				
$ per kilowatt	$ 0.02	$ 0.03	$ 0.03	$ 0.05
% cost escalation	--	5.0%	5.0%	5.0%
Non-Nuclear Generating Capacity: Placed in Service 1979-1990				
$ per kilowatt	$ 0.26	$ 0.32	$ 0.43	$ 0.60
% cost escalation	--	5.0%	5.0%	5.0%
Nuclear Generating Capacity: Placed in Service 1979-1990				
$ per kilowatt	$ 0.21	$ 0.26	$ 0.34	$ 0.48
% cost escalation	--	5.0%	5.0%	5.0%

[1] *These annual operating expendutres are in addition to those required to meet the 1977 guidelines.*

Source: EPA estimates

Exhibit 63

ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL CHEMICAL GUIDELINES, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.2	$ 28.4	$ 39.1
Total since 1973	--	61.3	204.7	443.3
Construction Work in Progress				
End of year	$ 19.6	$ 26.8	44.0	$ 62.3
External Financing				
Total for year	$ 7.6	$ 11.2	$ 18.0	$ 23.6
Total since 1973	--	36.7	127.4	273.7
Operating Revenues				
Total for year	$ 39.5	$ 52.8	$ 75.2	$ 104.7
Total since 1973	--	189.5	582.9	1,225.0
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.7	$ 38.3	$ 49.9
Total since 1973	--	92.5	294.6	608.2
Consumer Charges (mills/kWh)				
Average for year	21.4	24.2	23.8	22.5

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 64

ECONOMIC AND FINANCIAL IMPACT OF FINAL CHEMICAL GUIDELINES - 1977

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Chemical Requirements	Projections With Chemical Requirements
Capital Expenditures			
Total for year	$ 17.9	+ 0.3	$ 18.2
Total since 1973	60.3	+ 1.0	61.3
Construction Work in Progress			
End of year	26.5	+ 0.3	$ 26.8
External Financing			
Total for year	$ 10.9	+ 0.3	$ 11.2
Total since 1973	35.8	+ 0.9	36.7
Operating Revenues			
Total for year	$ 52.5	+ 0.3	$ 52.8
Total since 1973	188.8	+ 0.7	189.5
Operations and Maintenance Expenses[1]			
Total for year	$ 26.4	+ 0.3	$ 26.7
Total since 1973	92.0	+ 0.5	92.5
Consumer Charges (mills/kWh)			
Average for year	24.0	+ 0.2	24.2

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 65

ECONOMIC AND FINANCIAL IMPACT OF FINAL CHEMICAL GUIDELINES - 1983

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Chemical Requirements	Projections With Chemical Requirements
Capital Expenditures			
Total for year	$ 28.3	+ 0.1	$ 28.4
Total since 1973	203.2	+ 1.5	204.7
Construction Work in Progress			
End of year	$ 43.8	+ 0.2	$ 44.0
External Financing			
Total for year	$ 17.8	+ 0.2	$ 18.0
Total since 1973	126.3	+ 1.4	127.4
Operating Revenues			
Total for year	$ 74.7	+ 0.5	$ 75.2
Total since 1973	579.5	+ 3.4	582.9
Operations and Maintenance Expenses[1]			
Total for year	$ 38.0	+ 0.3	$ 38.3
Total since 1973	292.5	+ 2.1	294
Consumer Charges (mills/kWh)			
Average for year	23.6	+ 0.2	23.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 66

ECONOMIC AND FINANCIAL IMPACT OF FINAL CHEMICAL GUIDELINES - 1990

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Chemical Requirements	Projections With Chemical Requirements
Capital Expenditures			
Total for year	$ 39.1	+ 0.0	$ 39.1
Total since 1973	441.4	+ 1.9	443.3
Construction Work in Progress			
End of year	62.2	+ 0.1	$ 62.3
External Work in Progress			
Total for year	$ 23.6	+ 0.0	$ 23.6
Total since 1973	272.6	+ 1.1	273.7
Operating Revenues			
Total for year	$ 104.1	+ 0.6	$ 104.7
Total since 1973	$1,218.0	+ 7.0	$1,225.0
Operations and Maintenance Expenses[1]			
Total for year	$ 49.5	+ 0.4	$ 49.9
Total since 1973	603.7	+ 4.5	608.2
Consumer Charges (mills/kWh)			
Average for year	22.4	+ 0.1	22.5

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 67

ECONOMIC AND FINANCIAL IMPACT OF FINAL REGULATIONS - 1977

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Economic Reasons	Impact Final Regulations Thermal Requirements	Impact Final Regulations Chemical Requirements	Projections With Final Regulations
Capital Expenditures					
Total for year	$ 17.9	+ 0.1	+ 0.3	+ 0.3	$ 18.6
Total since 1973	60.3	+ 0.6	+ 0.9	+ 1.0	62.8
Construction Work in Progress					
End of year	$ 26.5	+ 0.2	+ 0.7	+ 0.3	$ 27.7
External Financing					
Total for year	$ 10.9	+ 0.1	+ 0.2	+ 0.3	$ 11.5
Total since 1973	35.8	+ 0.5	+ 0.8	+ 0.9	38.0
Operating Revenues					
Total for year	$ 52.5	+ 0.1	+ 0.1	+ 0.3	$ 53.0
Total since 1973	188.8	+ 0.2	+ 0.2	+ 0.7	189.9
Operations and Maintenance Expenses[1]					
Total for year	$ 26.4	+ 0.1	+ 0.0	+ 0.3	$ 26.8
Total since 1973	92.0	+ 0.1	+ 0.1	+ 0.5	92.7
Consumer Charges (mills/kWh)					
Average for year	24.0	+ 0.1	+ 0.0	+ 0.2	24.3
Capacity Losses (millions of kW)					
Total since 1973	--	+ 0.8	+ 0.8	--	1.6
Energy Penalty (Quads)					
Total for year	--	+ 0.1	+ 0.0	--	0.1

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 68

ECONOMIC AND FINANCIAL IMPACT OF FINAL REGULATIONS - 1983

(dollar figures in billions of 1974 dollars)

	Baseline Conditions	Impact of Economic Reasons	Impact Final Regulations		Projections With Final Regulations
			Thermal Requirements	Chemical Requirements	
Capital Expenditures					
Total for year	$ 28.3	+ 0.2	+ 0.3	+ 0.1	$ 28.9
Total since 1973	203.2	+ 1.9	+ 3.2	+ 1.5	209.8
Construction Work in Progress					
End of year	$ 43.8	+ 0.5	+ 0.5	+ 0.2	$ 45.0
External Financing					
Total for year	$ 17.8	+ 0.2	+ 0.2	+ 0.2	$ 18.4
Total since 1973	126.3	+ 1.5	+ 2.5	+ 1.4	131.7
Operating Revenues					
Total for year	$ 74.7	+ 0.4	+ 0.6	+ 0.5	$ 76.2
Total since 1973	579.5	+ 1.7	+ 2.4	+ 3.4	587.0
Operations and Maintenance Expenses[1]					
Total for year	$ 38.0	+ 0.1	+ 0.2	+ 0.3	$ 38.6
Total since 1973	292.5	+ 0.7	+ 0.9	+ 2.1	296.2
Consumer Charges (mills/kWh)					
Average for year	23.6	+ 0.1	+ 0.2	+ 0.2	24.1
Capacity Losses (millions of kW)					
Total since 1973	--	+ 3.0	+ 4.0	--	7.0
Energy Penalty (Quads)					
Total for year	--	+ 0.2	+ 0.2	--	0.4

---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibti 69

ECONOMIC AND FINANCIAL IMPACT OF FINAL REGULATIONS - 1990

(dollar figures in billions of 1974 dollars)

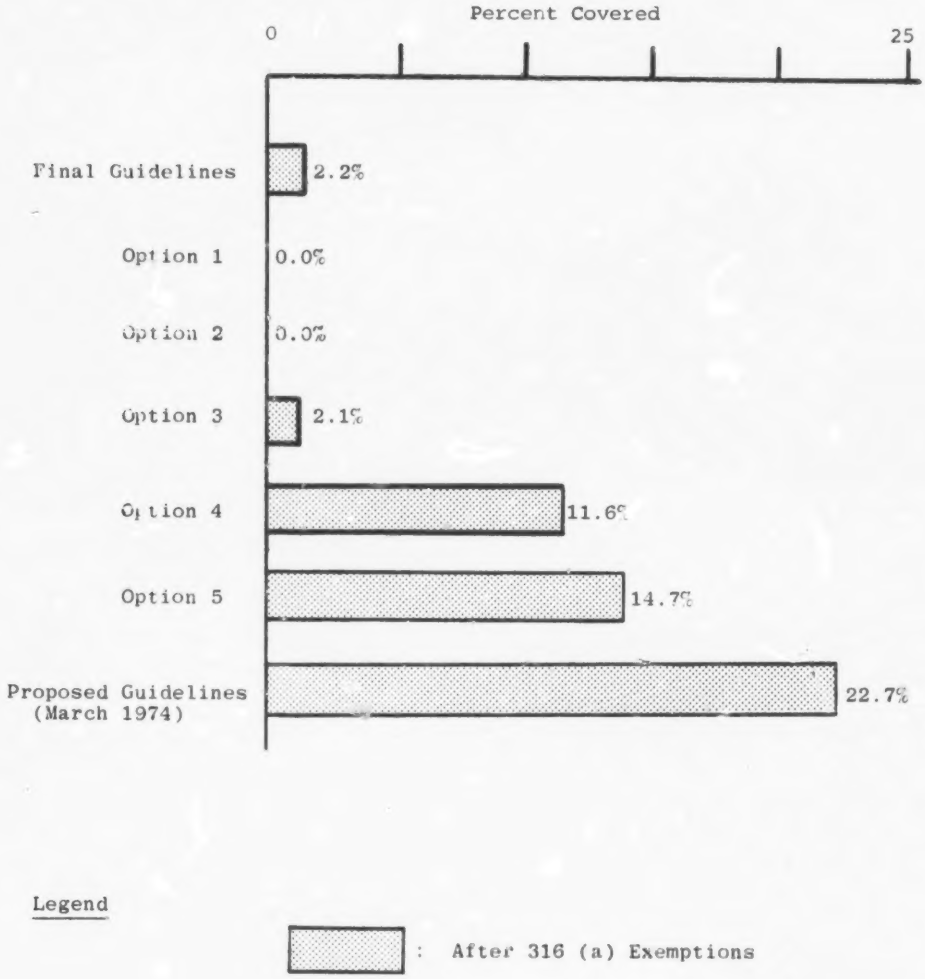
	Baseline Conditions	Impact of Economic Reasons	Impact Final Regulations		Projections With Final Regulations
			Thermal Requirements	Chemical Requirements	
Capital Expenditures					
Total for year	$ 39 1	+0.4	+0.3	+0.0	$ 39.8
Total since 1973	441.4	+4.1	+5.3	+1.9	452.7
Construction Work in Progress					
End of year	$ 62.2	+0.7	+0.8	+0.1	$ 63.8
External Financing					
Total for year	$ 23.6	+0.2	+0.2	+0.0	$ 24.0
Total since 1973	272.6	+2.9	+3.7	+1.1	280.3
Operating Revenues					
Total for year	$ 104.1	+0.8	+0.8	+0.6	$ 106.3
Total since 1973	1,218.0	+5.5	+7.7	+7.0	1,238.2
Operations and Maintenance Expenses[1]					
Total for year	$ 49.5	+0.3	+0.4	+0.4	$ 50.6
Total since 1973	603.7	+2.4	+3.0	+4.5	613.6
Consumer Charges (mills/kWh)					
Average for year	22.4	+0.2	+0.2	+0.1	22.9
Capacity Losses (millions of kW)					
Total since 1973	--	+7.0	+7.6	--	14.6
Energy Penalty (trillions of Btu's)					
Total for year	--	+0.4	+0.4	--	0.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 70

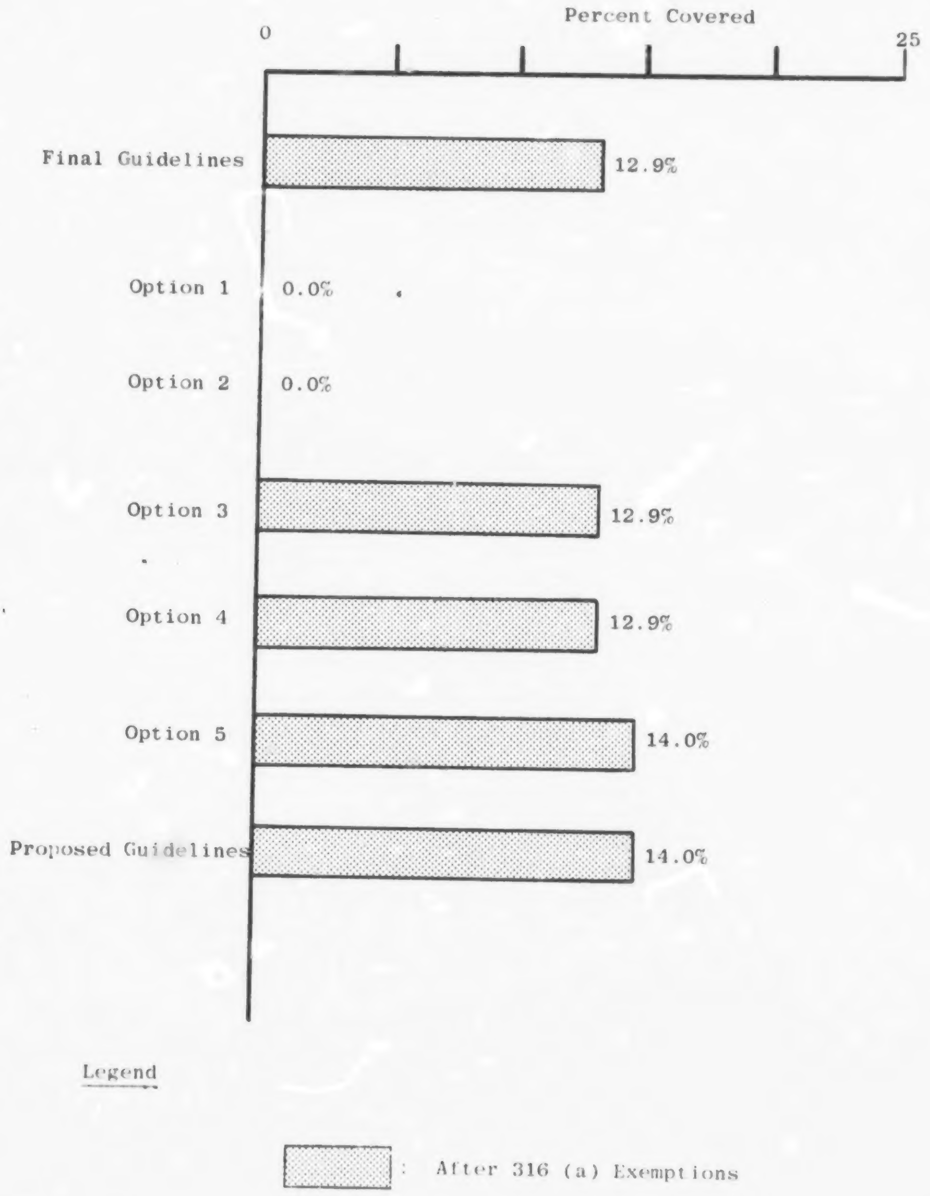
NON-NUCLEAR COVERAGE FOR EXISTING UNITS



Source: ERCO, EPA estimates

Exhibit 71

NUCLEAR COVERAGE FOR EXISTING UNITS



Source: ERCO, EPA estimates

~ Exhibit 72

ECONOMIC AND FINANCIAL PROJECTIONS OF OPTION 1 (1979) AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.1	$ 28.8	$ 39.8
Total since 1973	--	61.4	207.0	449.4
Construction Work in Progress				
End of year	$ 19.6	$ 27.0	$ 44.8	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.1	$ 18.2	$ 24.1
Total since 1973	--	36.8	129.3	278.4
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 75.4	$ 105.5
Total since 1973	--	189.2	582.7	1,228.7
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.3	$ 50.1
Total since 1973	--	92.2	293.9	608.3
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	23.8	22.7
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	5.9	13.6
Energy Penalty (Quads)				
Total for year	--	0.1	0.4	0.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibti 73

ECONOMIC AND FINANCIAL PROJECTIONS OF OPTION 2 (1974) AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.2	$ 28.8	$ 39.8
Total since 1973	--	61.7	207.9	450.3
Construction Work in Progress				
End of year	$ 19.6	$ 27.2	$ 44.8	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 18.2	$ 24.0
Total since 1973	--	37.0	130.0	279.0
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 75.6	$ 105.7
Total since 1973	--	189.2	583.3	1,230.4
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.3	$ 50.2
Total since 1973	--	92.2	294.0	608.8
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	23.9	22.8
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	6.6	14.3
Energy Penalty (Quads)				
Total for year	--	0.1	0.4	0.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 74

ECONOMIC AND FINANCIAL PROJECTIONS OF OPTION 3 (1972) AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.2	$ 28.9	$ 39.8
Total since 1973	--	61.7	208.4	450.8
Construction Work in Progress				
End of year	$ 19.6	$ 27.3	$ 44.9	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 18.2	$ 24.0
Total since 1973	--	37.1	130.3	279.2
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 75.7	$ 105.7
Total since 1973	--	189.2	583.6	1,231.2
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.3	$ 50.2
Total since 1973	--	92.2	294.1	609.1
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	23.9	22.8
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	7.0	14.6
Energy Penalty (Quads)				
Total for year	--	0.1	0.4	0.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 75

ECONOMIC AND FINANCIAL PROJECTIONS OF OPTION 4 (1961, <200 MW) AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.2	$ 30.1	$ 39.8
Total since 1973	--	61.7	210.1	452.0
Construction Work in Progress				
End of year	$ 19.6	$ 27.3	$ 45.4	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 19.3	$ 24.0
Total since 1973	--	37.1	131.8	280.0
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 75.9	$ 106.0
Total since 1973	--	189.2	583.9	1.233.2
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.5	$ 50.3
Total since 1973	--	92.2	255.8	609.8
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	24.0	22.8
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	8.1	15.8
Energy Penalty (Quads)				
Total for year	--	0.1	0.3	0.9

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 76

ECONOMIC AND FINANCIAL PROJECTIONS OF OPTION 5 (1956, < 25 MW, < 40%) AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.2	$ 30.6	$ 39.8
Total since 1973	--	61.7	210.7	452.4
Construction Work in Progress				
End of year	$ 19.6	$ 27.3	$ 45.6	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 19.7	$ 24.0
Total since 1973	--	37.1	132.4	280.3
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 76.0	$ 106.0
Total since 1973	--	189.2	584.0	1,233.9
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.5	$ 50.3
Total since 1973	--	92.2	294.3	610.0
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	24.0	22.8
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	8.5	16.1
Energy Penalty (Quads)				
Total for year	--	0.1	0.5	0.9

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 77

ECONOMIC AND FINANCIAL PROJECTIONS OF PROPOSED GUIDELINES (MARCH 1974) AFTER SECTION 316(a) EXEMPTIONS, FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.3	$ 31.8	$ 39.8
Total since 1973	--	61.8	212.1	453.4
Construction Work in Progress				
End of year	$ 19.6	$ 27.4	$ 46.1	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 20.9	$ 24.0
Total since 1973	--	68.0	133.7	281.0
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 76.2	$106.2
Total since 1973	--	189.2	584.3	1,235.7
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.5	$ 38.7	$ 50.4
Total since 1973	--	92.2	294.5	610.6
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	24.1	22.9
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	9.4	17.1
Energy Penalty (Quads)				
Total for year	--	0.1	0.5	1.0

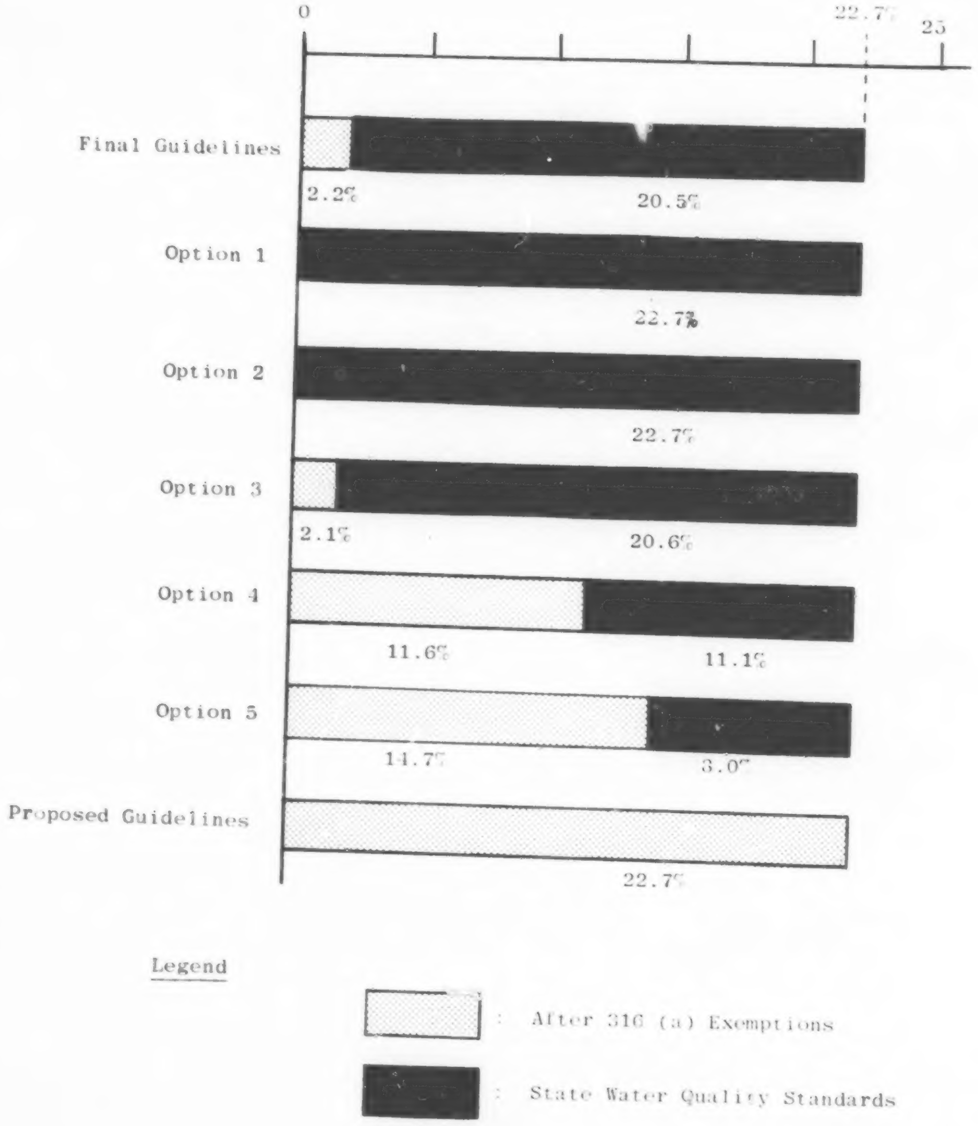
---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 78

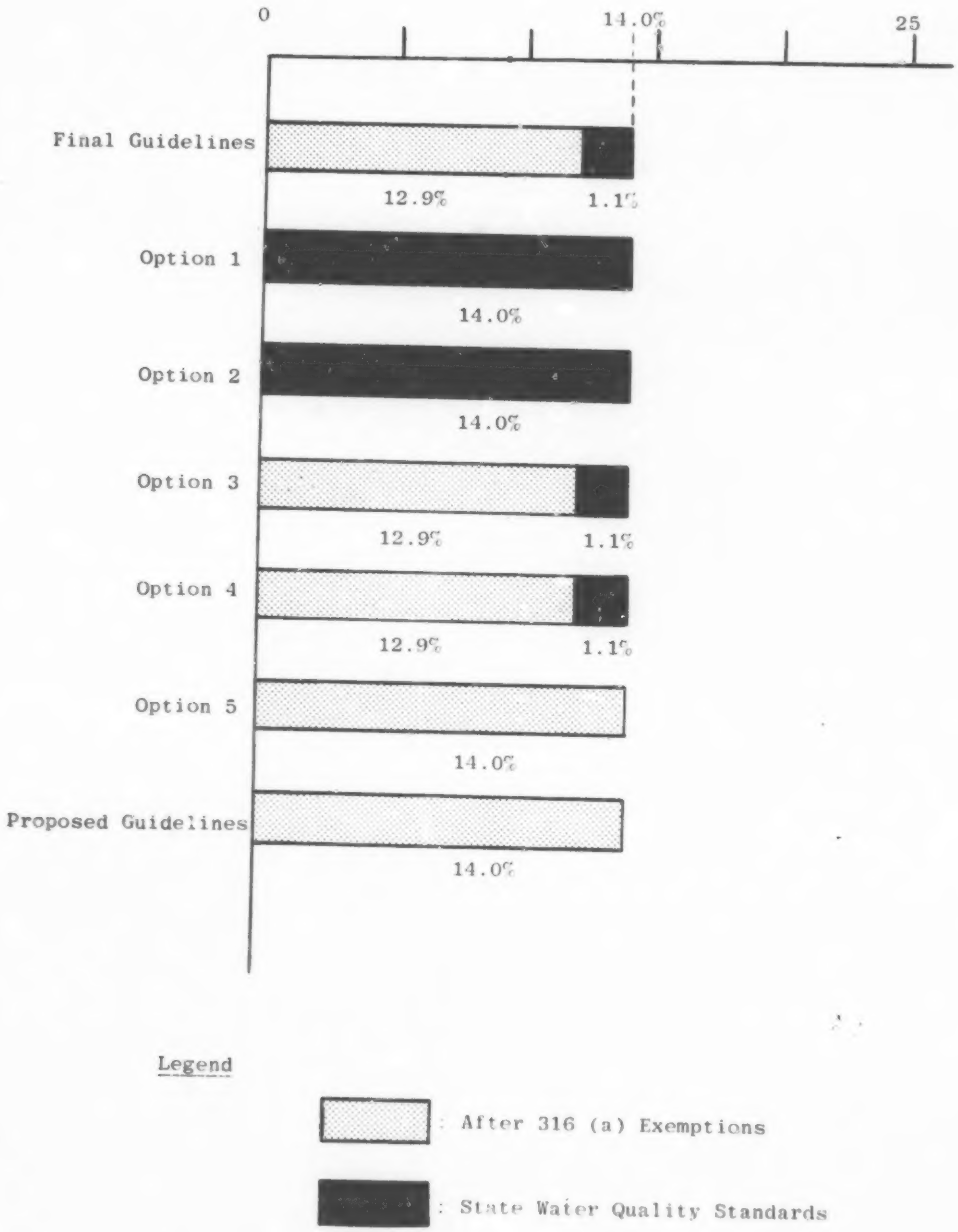
NON-NUCLEAR COVERAGE FOR EXISTING UNITS



Source: ERCO, EPA estimates

Exhibit 79

NUCLEAR COVERAGE FOR EXISTING UNITS



Source: ERCO, EPA estimates

Exhibit 80

ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL THERMAL GUIDELINES AFTER SECTION 316(a) EXEMPTIONS AND AFTER STATE WATER QUALITY STANDARDS FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 18.3	$ 31.8	$ 39.8
Total since 1973	--	61.8	212.1	453.4
Construction Work in Progress				
End of year	$ 19.6	$ 27.4	$ 46.1	$ 63.7
External Financing				
Total for year	$ 7.6	$ 11.2	$ 20.9	$ 24.0
Total since 1973	--	68.0	133.7	281.0
Operating Revenues				
Total for year	$ 39.5	$ 52.7	$ 76.2	$106.2
Total since 1973	--	189.2	584.3	1,235.7
Operations and Maintenance Expenses[1]				
Total for year	$ 17.7	26.5	38.7	50.4
Total since 1973	--	92.2	294.5	610.6
Consumer Charges (mills/kWh)				
Average for year	21.4	24.1	24.1	22.9
Capacity Losses (millions of kW)				
Total since 1973	--	1.6	9.4	17.1
Energy Penalty (Quads)				
Total for year	--	0.1	0.5	1.0

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 81

ECONOMIC AND FINANCIAL IMPACT OF STATE WATER QUALITY STANDARDS - 1977

	Projections After 316(a) Exemptions	Impact of State Water Quality Standards (SWQS)	Projections After 316(a) Exemptions and SWQS
Capital Expenditures			
Total for year	$ 18.3	+ 0.0	$ 18.3
Total since 1973	61.8	+ 0.0	61.8
Construction Work in Progress			
End of year	$ 27.4	+ 0.0	$ 27.4
External Financing			
Total for year	$ 11.2	+ 0.0	$ 11.2
Total since 1973	37.1	+ 0.0	37.1
Operating Revenues			
Total for year	$ 52.7	+ 0.0	$ 52.7
Total since 1973	189.2	+ 0.0	189.2
Operations and Maintenance Expenses[1]			
Total for year	$ 26.5	+ 0.0	$ 26.5
Total since 1973	92.2	+ 0.0	92.2
Consumer Charges (mills/kWh)			
Average for year	24.1	+ 0.0	24.1
Capacity Losses (millions of kW)			
Total since 1973	1.6	+ 0.0	1.6
Energy Penalty (Quads)			
Total for year	0.1	+ 0.0	0.1

---

[1] *Excludes nuclear fuel.*

Source: PTm

Exhibit 82

ECONOMIC AND FINANCIAL IMPACT OF STATE WATER QUALITY STANDARD - 1983

	Projections After 316(a) Exemptions	Impact of State Water Quality Standards (SWQS)	Projections After 316(a) Exemptions and SWQS
Capital Expenditures			
Total for year	$ 28.8	+ 3.0	$ 31.8
Total since 1973	208.3	+ 3.9	212.2
Construction Work in Progress			
End of year	$ 44.8	+ 1.3	$ 46.1
External Financing			
Total for year	$ 18.2	+ 2.7	$ 20.9
Total since 1973	130.3	+ 3.4	133.7
Operating Revenues			
Total for year	$ 75.7	+ 0.5	$ 76.2
Total since 1973	583.6	+ 0.7	584.3
Operations and Maintenance Expenses[1]			
Total for year	$ 38.3	+ 0.4	$ 38.7
Total since 1973	294.1	+ 0.4	294.5
Consumer Charges (mills/kWh)			
Average for year	23.9	+ 0.2	24.1
Capacity Losses (millions of KWh)			
Total since 1973	7.0	+ 2.4	9.4
Energy Penalty (Quads)			
Total for year	0.4	+ 0.1	0.5

---

[1] *Excludes nuclear fuel.*

Source: PTm

Exhibit 83

ECONOMIC AND FINANCIAL IMPACT OF STATE WATER QUALITY STANDARDS - 1990

	Projections After 316(a) Exemptions	Impact of State Water Quality Standards (SWQS)	Projections After 316(a) Exemptions and SWQS
Capital Expenditures[1]			
Total for year	$ 39.8	+ 0.0	$ 39.8
Total since 1973	450.8	+ 2.6	453.4
Construction Work in Progress			
End of year	$ 63.7	+ 0.0	$ 63.7
External Financing			
Total for year	$ 24.0	+ 0.0	$ 24.0
Total since 1973	279.2	+ 1.8	281.0
Operating Revenues			
Total for year	$ 105.7	+ 0.5	$ 106.2
Total since 1973	1,231.2	+ 4.5	$1,235.7
Operations and Maintenance Expenses[1]			
Total for year	$ 50.2	+ 0.2	$ 50.4
Total since 1973	609.1	+ 1.5	610.6
Consumer Charges (mills/kWh)			
Average for year	22.8	+ 0.1	22.9
Capacity Losses (millions of kW)			
Total since 1973	14.6	+ 2.5	17.1
Energy Penalty (Quads)			
Total for year	0.8	+ 0.2	1.0

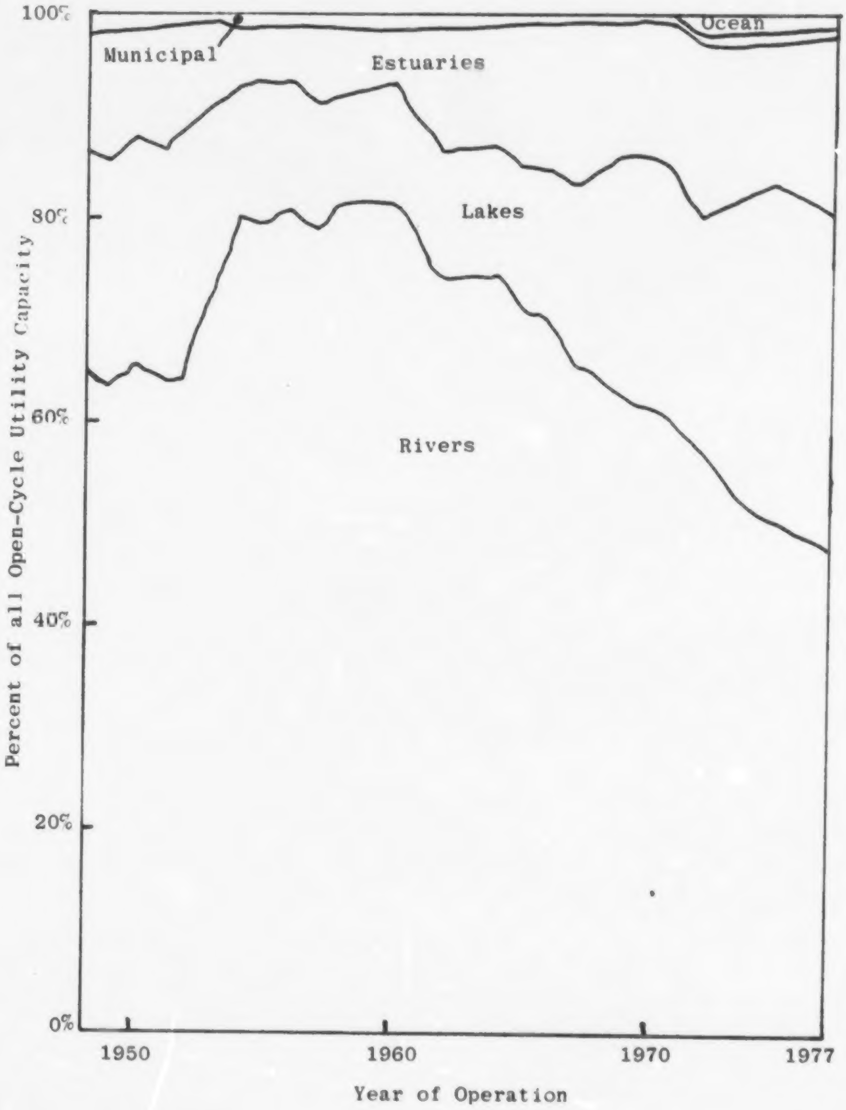
---

[1] *Excludes nuclear fuel.*

Source: PTm

Exhibit 84

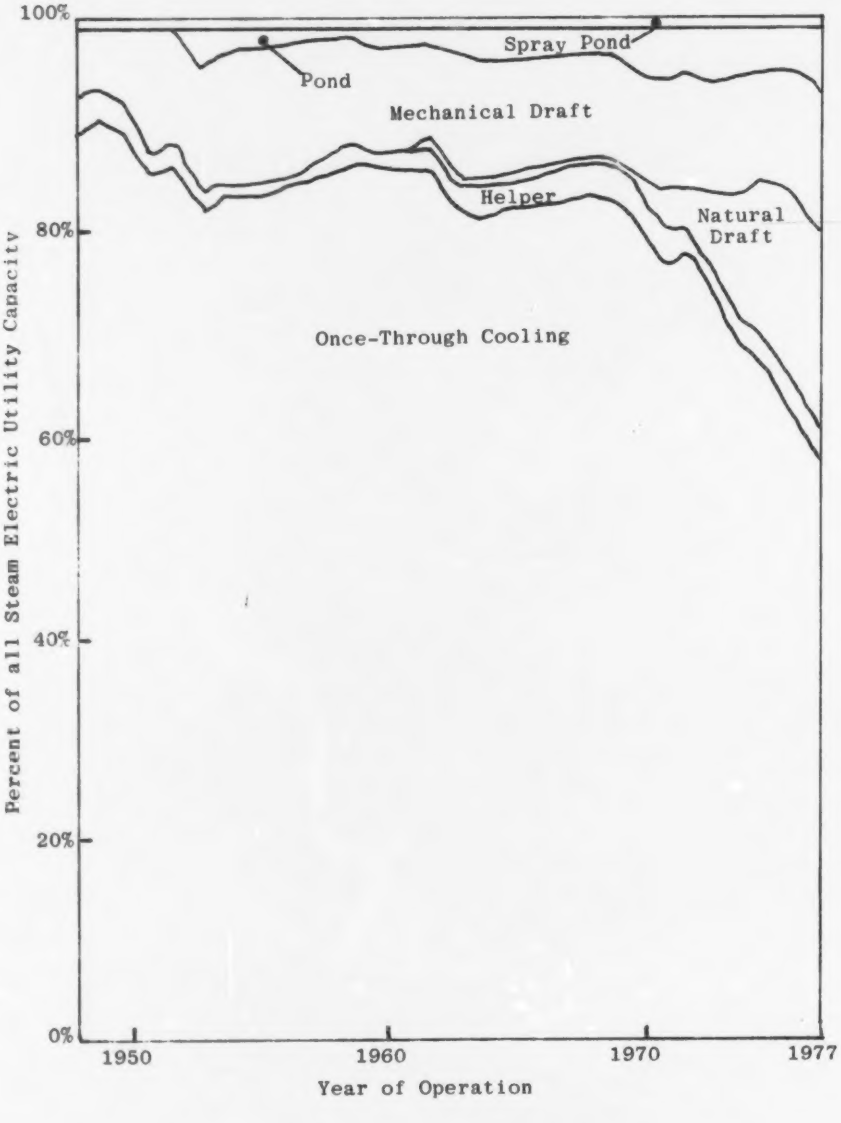
ANNUAL MIX OF RECEIVING WATER TYPES - OPEN CYCLE STEAM ELECTRIC CAPACITY



Source: Sample of 180 Steam Electric Utility Plants, 1974

Exhibit 85

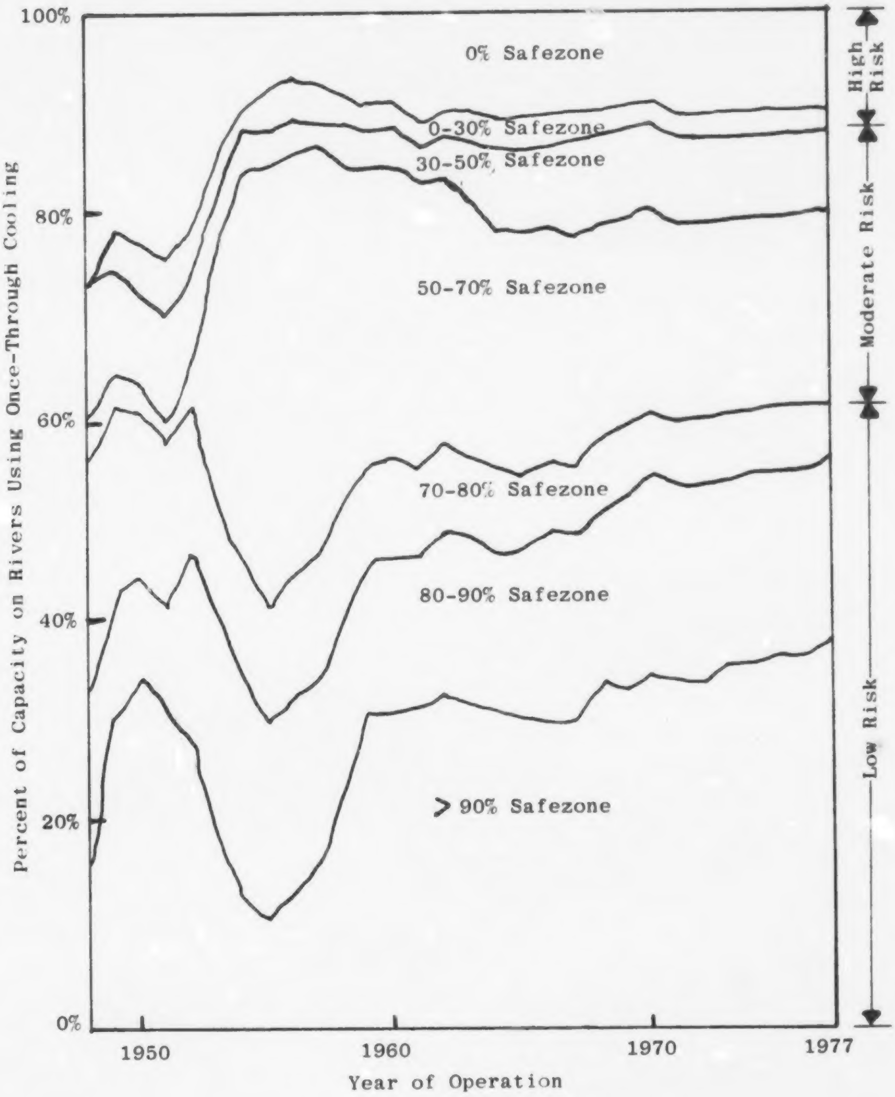
ANNUAL MIX OF COOLING METHOD- STEAM ELECTRIC CAPACITY



Source: Sample of 180 Steam-Electric Utility Plants, 1974

Exhibit 86

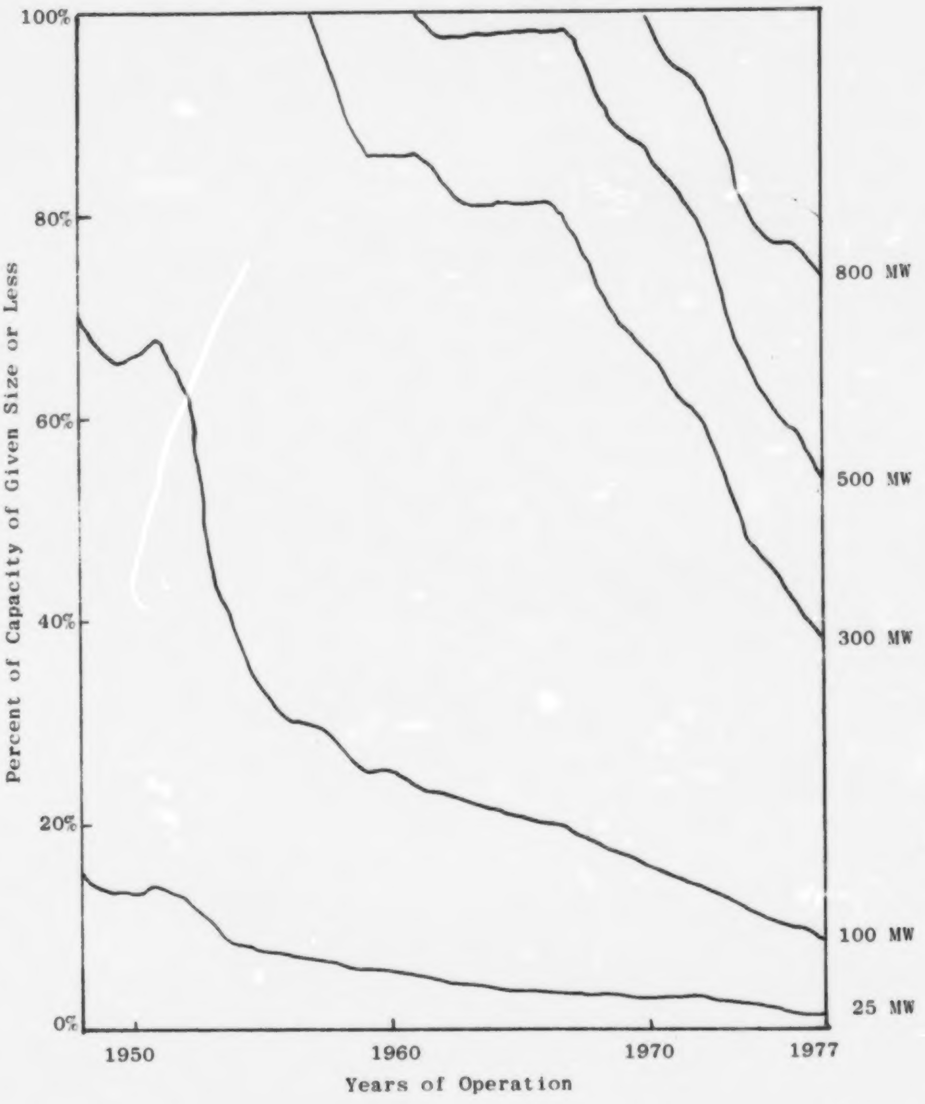
SAFEZONE ON RIVERS USED FOR ONCE-THROUGH COOLING
(percent of river flow not affected by thermal effluent)



Source: Sample of 180 Steam Electric Utility Plants, 1974

Exhibit 87

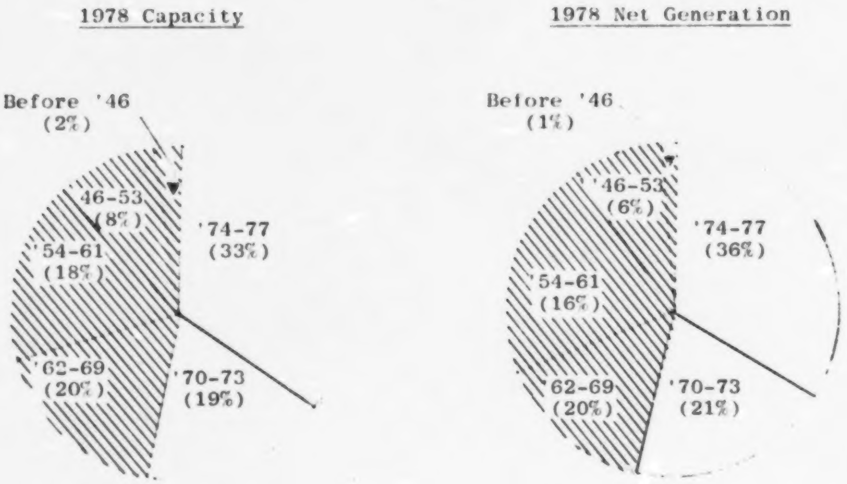
MIX OF CAPACITY BY UNIT SIZE



Source: Sample of 180 Steam Electric Utility Plants, 1974

Exhibit 88

DISTRIBUTION OF PROJECTED 1978 UNITS BY YEAR PLACED IN SERVICE



(Shaded area represents portion exempted under final option by year placed in service)

Source: Sample of 180 Steam Electric Utility Plants, 1974

Exhibit 89

COMPARISON OF CAPACITY PROJECTIONS USED FOR ENVIRONMENTAL VERSUS ECONOMIC ANALYSIS

	Fossil and Nuclear Capacity (millions of kilowatts)		
Capacity	Economic Analysis Projection (Moderate Growth)	Environmental Analysis Projections	Percent Difference
January 1, 1974	355.1	340	-4.3%
January 1, 1978	440.4	426	-3.3%
January 1, 1983	580.9	573	-1.4%

Source: ERCO and PTm

Exhibit 90

AGE COMPOSITION AND RISK CHARACTERISTICS OF CAPACITY IN-SERVICE BY 1983

Year Placed In-Service	% of 1983 Capacity	% High Risk	% Low Risk	% Closed Cycle
Prior to 1970, still in operation in 1983	37.7%	30.0%	56.0%	14.0%
1970-1973, < 500 MW	4.4%	16.0%	25.0%	59.0%
1970-1973, ≥ 500 MW	12.7%	16.0%	25.0%	59.0%
1974-1977	16.8%	16.0%	18.0%	66.0%
1978-1982	28.4%	16.0%	18.0%	66.0%
Combined	100.0%	21.5%	33.3%	45.2%

Exhibit 91

Environmental Risk
Variations on 1970-73 Size Criterion
With 1970 Exemption

▨ = Exempted

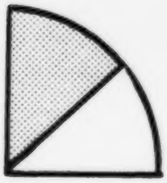
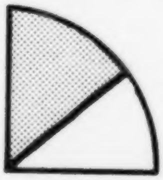
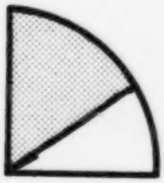
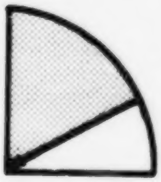
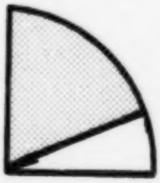
1970-73 Size Criterion		% Capacity Exempted (% Net Generation Exempted)	
		% 1983 High Risk Units	% All 1983 Fossil and Nuclear Units
0 Mw (Pure 1970)		53% (40%)	11% (8%)
300 Mw		55% (43%)	12% (8%)
500 Mw (Final Option)		56% (44%)	12% (8%)
700 Mw		59% (46%)	13% (9%)
1300 Mw (Pure 1974)		66% (54%)	14% (10%)

Exhibit 92

▨ = Exempted

Environmental Risk
Alternative Age Criteria

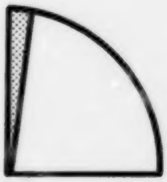
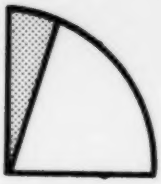
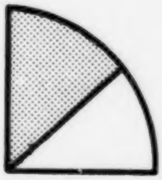
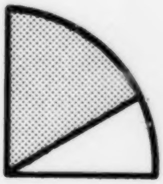
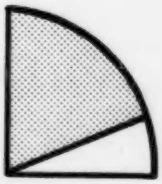
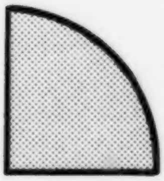
		% Capacity Exempted (% Net Generation Exempted)	
Year Exempted		% 1983 High Risk Units	% All 1983 Fossil and Nuclear Units
1950		4% (1%)	Less than 1% (0.2%)
1961		24% (19%)	5% (4%)
1970		52% (40%)	11% (8%)
1974		66% (54%)	14% (10%)
1978		79% (71%)	17% (14%)
1983		100% (100%)	22% (19%)

Exhibit 93

A SUMMARY OF ALTERNATIVE ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL THERMAL GUIDELINES FOR THE PERIOD 1974-1983

(dollar figures in billion of 1974 dollars)

Capacity Coverage:	--	Economic Reasons		After 316(a) Exemptions	
Capital and Operating Cost Estimates:	--	EPA	UWAG	EPA	UWAG
	NPS Baseline Conditions	Economic Reasons	UWAG Case #1	After 316(a) Exemptions	UWAG Case #2
Capital Expenditures					
Total since 1973	$203.2	$205.1	$205.3	$208.4	$208.8
Construction Work in Progress					
Increase since 1973	$ 24.2	$ 24.7	$ 24.7	$ 25.2	$ 25.3
External Financing					
Total since 1973	$126.3	$127.8	$128.3	$130.3	$130.6
Operating Revenues					
Total since 1973	$579.5	$581.2	$581.9	$583.6	$586.0
Operations & Maintenance Expenses[1]					
Total since 1973	$292.5	$293.2	$293.9	$294.1	$296.1
Consumer Charges (mills/kWh)					
Average for year	23.6	23.7	23.8	23.9	24.1
Capacity Losses (millions of kW)					
Total since 1973	--	3.0	3.0	7.0	7.0
Energy Penalty (Quads)					
Total for year	--	0.2	0.2	0.4	0.4

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 94

A SUMMARY OF ALTERNATIVE ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL CHEMICAL GUIDELINES FOR THE PERIOD 1974-1983

(dollar figures in billions of 1974 dollars)

Capital and Operating Cost Estimates:	-	EPA	UWAG
	NPS Baseline Conditions	Chemical	UWAG Case #3
Capital Expenditures			
Total since 1973	$203.2	$204.7	$206.5
Construction Work in Progress			
Increase since 1973	$ 24.2	$ 24.3	$ 24.3
External Financing			
Total since 1973	$126.3	$127.4	$128.5
Operating Revenues			
Total since 1973	$579.5	$582.9	$584.7
Operations and Maintenance Expenses[1]			
Total since 1973	$292.5	$294.6	$294.5
Consumer Charges (mills/kWh)			
Average for year	23.6	23.8	23.8

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 95

A SUMMARY OF ALTERNATIVE ECONOMIC AND FINANCIAL PROJECTIONS OF BASELINE CONDITIONS FOR THE PERIOD 1974-1983

(dollar figures in billions of 1974 dollars)

Industry Growth Rate Assumptions:	Moderate	Historic	Historic
Interest and Preferred Dividend Rate Assumptions:	NPS	NPS	UWAG
	NPS Baseline Conditions	Historic Conditions	UWAG Case #4
Capital Expenditures			
Total since 1973	$203.2	$245.6	$245.6
Construction Work in Progress			
Increase since 1973	$ 24.2	$ 33.9	$ 33.9
External Financing			
Total since 1973	$126.3	$158.5	$158.5
Operating Revenues			
Total since 1973	$579.5	$619.3	$634.1
Operations & Maintenance Expenses[1]			
Total since 1973	$292.5	$306.6	$306.6
Consumer Charges (mills/kWh)			
Average for year	23.6	23.9	24.6

---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 96

A SUMMARY OF ALTERNATIVE ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL THERMAL GUIDELINES FOR THE PERIOD 1974-1983

(dollar figures in billions of 1974 dollars)

Capacity Coverage	-	Economic Reasons	After 316(a) Exemptions
Capital and Operating Cost Estimates	-	EPA	EPA
	UWAG Case #4	UWAG Case #5	UWAG Case #6
Capital Expenditures			
Total since 1973	$245.6	$247.8	$251.6
Construction Work in Progress			
Increase since 1973	$ 33.9	$ 34.5	$ 35.2
External Financing			
Total since 1973	$158.5	$160.3	$163.2
Operating Revenues			
Total since 1973	$634.1	$636.2	$639.4
Operations and Maintenance Expenses[1]			
Total since 1973	$306.6	$307.5	$308.6
Consumer Charges (mills/kWh)			
Average for year	24.6	24.8	25.0
Capacity Losses (millions of kw)			
Total since 1973	-	3.6	8.2
Energy Penalty (Quads)			
Total for year	-	0.2	0.5

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 97

A SUMMARY OF ALTERNATIVE ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL THERMAL GUIDELINES FOR THE PERIOD 1974-1983

(dollar figures in billions of 1974 dollars)

Capacity Coverage	-	Economic Reasons	After 316(a) Exemptions
Capital and Operating Cost Estimates	-	UWAG	UWAG
	UWAG Case #4	UWAG Case #7	UWAG Case #8
Capital Expenditures			
Total since 1973	$245.6	$248.0	$252.1
Construction Work in Progress			
Increase since 1973	$ 33.9	$ 34.5	$ 35.2
External Financing			
Total since 1973	$158.5	$160.4	$163.6
Operating Revenues			
Total since 1973	$634.1	$637.2	$642.2
Operations and Maintenance Expenses[1]			
Total since 1973	$306.6	$308.2	$310.9
Consumer Charges (mills/kWh)			
Average for year	24.6	24.8	25.2
Capacity Losses (millions of kw)			
Total since 1973	-	3.6	8.2
Energy Penalty (Quads)			
Total for year	-	0.2	0.5

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit 98

A SUMMARY OF ALTERNATIVE ECONOMIC AND FINANCIAL PROJECTIONS OF FINAL CHEMICAL GUIDELINES FOR THE PERIOD 1974-1983

(dollar figures in billions of 1974 dollars)

Capital and Operating Cost Factors	-	EPA	UWAG
	UWAG Case #4	UWAG Case #9	UWAG Case #10
Capital Expenditures			
Total since 1973	$245.6	$247.2	$249.0
Construction Work in Progress			
Increase since 1973	$ 33.9	$ 34.0	$ 34.0
External Financing			
Total since 1973	$158.5	$159.6	$160.8
Operating Revenues			
Total since 1973	$634.1	$637.7	$639.8
Operations and Maintenance Expenses[1]			
Total since 1973	$306.6	$308.7	$308.7
Consumer Charges (mills/kWh)			
Average for year	24.6	24.8	24.9

---

[1] *Excludes nuclear fuel*

Source: PTm

APPENDIX A: PTm RESEARCH METHODOLOGY

INTRODUCTION

This appendix on research methodology consists of a non-technical overview of the logical structure of the computer model used to derive the projections discussed and analyzed in the text of this report. The model, called PTm, is an extension of a model developed by Drs. Howard W. Pifer and Michael L. Tennican of Temple, Barker & Sloane, Inc. to provide projections for the Technical Advisory Committee on Finance to the 1973-1974 National Power Survey.[1]

In broad terms, PTm has three main logical components, which may conveniently be labeled the environmental, physical, and financial modules. As shown in Figure 1, it is assumed that general economic conditions and other factors outside the model determine the demand for electricity. Consumers' peak and average demand, the industry's policy with respect to reserve margins, and the equipment, power drain, and generating efficiency implications of pollution control requirements combine to determine the industry's physical plant, equipment, fuel, and labor requirements. These physical requirements and the relevant factor costs, which are also influenced by economic considerations external to PTm, combine to determine the consequences of building and operating the capacity needed to meet consumer demand.

---

[1] *Drs. Pifer and Tennican gratefully acknowledge the counsel and assistance of a number of individuals from industry, the Federal Power Commission, and various financial institutions -- especially Messrs. John Childs, Gordon Corey, Fred Eggerstedt, Robert Fortune, John Glover, Rene Males, John O'Connor, and Robert Uhler.*

These capital asset and operating cash requirements are met in part by revenues collected from the users of electrical energy and in part by external financing. The amount of cash provided by operations at any given point in time is influenced by regulatory policy (in effect via the allowed revenue per kilowatt hour), by tax policy (via the effective rate of taxation after consideration of depreciation tax shields, investment tax credits, etc.), and by the cost of capital raised in prior periods. Any shortfall between cash needs and the cash provided by operations is met by recourse to the capital markets.

Figure A-1 omits a number of interactions and feedbacks, two of which might be noted explicitly. First, if external financing is to be available, regulatory policy must be such as to allow revenues per kilowatt hour sufficient to yield returns to capital that are adequate in light of prevailing capital market conditions, tax policy, and pollution control requirements, all of which may have an impact on the cost of electrical power and hence on demand. As a second illustration, because the financial characteristics of the electric utility industry and of individual utilities may be considerations in the drafting and administration of pollution control legislation, pollution control policy in part determines and in part is determined by the industry's financial profile.

ENVIRONMENTAL MODULE

The model's environmental module has as its primary function the inputting of assumptions concerning future growth in the demand for power, current and future pollution control requirements, equipment and operating costs, etc. The implications of these policy, economic and technical assumptions are then determined in the physical and financial modules of PTm. PTm is programmed so as to be able to test a wide variety of policy alternatives via changes in input data. In testing alternative policies with respect to the coverage and time phasing of water pollution control requirements, however, modifications to the logical structure of the model itself were required, so that a series of slightly different models were actually used to make the projections set out in the body of the report. Nonetheless, for simplicity we shall in the following speak of PTm as a single model rather than as a set of related models.

PHYSICAL PLANT AND EQUIPMENT MODULE

The primary relationships determining the industry's physical plant and equipment requirements are shown in Figure A-2. Consistent with the assumption that demand will be met, the industry's gross generation capacity in service as of any point in time is determined by the level of demand, the industry's policy with respect to capacity reserves, and the efficiency impact and operation power drain of pollution control equipment. These current capacity requirements and the rate of retirement of old generating units together determine the amount of generating capacity additions necessary for meeting current demand. With the inclusion of the pollution control equipment required for generating capacity currently in service, the additions to in-service plant and related equipment are fully specified in physical terms.

Given the long time lags involved in constructing new generating capacity, the industry's plant and equipment construction as of any point in time typically includes significant amounts of work in progress so as to meet future demand as it materializes. As is shown in Figure A-2, future demand, future reserve factors, future pollution control requirements, and future retirements – together with the lags in construction – determine the plant and equipment additions that are related to future demand, i.e., construction in progress. It should be noted that because the time span between ordering and placing generating capacity in service is radically different for peaking units, fossil-fueled base load plants, and nuclear units, PTm computes construction work in progress for nuclear and for non-nuclear plants via two different time schedules. Thus, average construction lags are themselves a function of the assumed future mix of these various types of generating plants. It might also be noted that PTm is designed to accept assumptions with respect to the relative proportions of nuclear and fossil additions that change over time.

FINANCIAL MODULE

For expositional purposes it is convenient to divide PTm's financial module into three segments, dealing with:

- uses of funds,
- sources of funds, and
- revenues, expenses, and profits.

USES OF FUNDS

The industry's uses of funds depicted in Figure A-3 are determined primarily by the physical plant and equipment required to meet current and future demand and by the cost per unit of this equipment. A second use is the allowance on funds tied up in plant and equipment in the process of construction. For simplicity, PTm assumes that the industry's net working capital remains constant, so that changes in working capital appear neither as a use nor as a source of funds. Given the miniscule size of such working capital changes relative to the industry's major sources and uses of funds, such a simplifying assumption is unlikely to introduce appreciable error absent fundamental structural changes in the industry's current assets and payables accounts or in its usage of short-term debt.

As may be clear from Figure A-3, once the total physical amounts of plant and equipment required to meet current and future demand and the proportions of those amounts accounted for by nuclear and fossil-fueled plants are determined, the crucial input assumptions required to convert these physical quantities into financial terms are the cost per unit of each type of asset and the schedule of payments required by contractors while such plant and equipment are under construction.

SOURCES OF FUNDS

In the case of the private sector of the electric utility industry, sources of funds consist of two major elements, namely:

- funds provided by operations, and
- external financing.

Funds provided by operations in turn are the sum of three internal sources, namely:

- depreciation,
- tax deferrals, and
- retained earnings.

For the public sector, it is simply assumed that a percentage of total funds used are met from internal sources. As is shown in Figure 4a, any shortfall between total uses and internal sources is met via external financing.

Figure A-4b shows these same relationships in a format that is slightly different and that shows how the private sector's total required external financing and capital structure and dividend policies combine to determine:

- cash issues of preferred stock,
- gross cash offerings of debt, and
- cash issues of common stock.

REVENUES AND RELATED VARIABLES

The third segment of the financial module determines total industry revenues, expenses, profits, and related statistics such as price per kilowatt hour and interest coverage ratios. The output variables of this revenue segment serve in many instances as inputs to other segments (e.g., the depreciation expense figure computed in the revenue segment is an input to the sources of funds segment). Conversely, certain of the input variables to the revenue segment are based on the output from the sources and uses segment of the financial module (e.g., plant and equipment expenditures provide the base for computing depreciation expense). The structure of the revenue segment and the interactions between this segment and other parts of the total model are depicted in Figure A-5.

As shown at the top of Figure A-5, profits available for common stockholders are assumed to be determined completely by the amounts of the industry's common equity capital and by a rate of return on equity set by regulatory policy.[2] As a consequence of this assumption, revenues and prices per kilowatt hour of electricity are determined by required profits, other capital charges, and operating expenses.

Earnings before interest and taxes (EBIT) are simply the sum of EBT and interest expense and are computed by the same general process used for preferred dividends. The resultant EBIT figure constitutes one of the five main determinants of revenues.

The second determinant of revenues, depreciation and amortization of plant and equipment, is a variable related to the amount of plant and equipment in service. Presuming taxes other than on income consist primarily of property taxes, a third determinant of

---

2. *It should be noted that "policy" is a term intended to comprise the effect of both the target rates of return set by individual regulatory bodies and the administrative lags involved in adjusting prices per kilowatt hour so as to achieve such target returns.*

revenue, namely other taxes, is also related to the amount of plant and equipment in service. Plant and equipment requirements are in turn determined by both current demand and pollution control policy.

Current consumer demand and the power drains and operating efficiency losses associated with pollution control equipment combine to determine the level of operating and maintenance expenses. This latter expense figure is the fourth determinant of revenues.

Future consumer demand and pollution control requirements also determine future in-service plant and equipment requirements and hence determine the amount of construction currently in progress. The amount of construction in progress in turn determines the allowance for funds used during construction, which is another non-cash item, but which also affects - this time diminishes - the level of revenues required to achieve a given level of profit as determined by regulatory accounting procedures. This allowance on construction funds variable is the fifth and last major determinant of revenues.

Net profit is simply the sum of profits available for common stock and preferred dividends. The amounts of preferred dividends are determined by the amounts of preferred equity capital and the average dividend rate on the industry's outstanding preferred stock. The dividend yield on new preferred stock issues - and hence the average yield - is in turn determined over time by the reaction of the capital market to the industry's offerings.

Earnings before income taxes (EBT) are then set at a level such that EBT minus taxes will be equal to the required net profit figure. The tax expense figures (or equivalently, the effective tax rate) is itself a function of the EBT figure, which is computed in accordance with regulatory accounting procedures, and several other factors. The calculations are somewhat complicated first of all because various special features of the tax code (e.g., provisions allowing investment tax credits and accelerated depreciation) and of regulatory accounting (e.g., the creation of allowances for funds used during construction as non-cash credits to income) must be taken into account. As a consequence of these differing provisions, taxable EBT and regulatory EBT may - and typically do - differ. Secondly, as mentioned earlier, there exist two substantially different regulatory methods for determining the tax expense figure to be associated with EBT. Normalizing accounting gives rise to deferred taxes, which is a non-cash charge against income but which nonetheless constitutes an accounting expense to be covered by revenues if accounting profits to stockholders are to reach prescribed levels.

A CONCLUDING COMMENT

As has been outlined above, the operating, financial, tax, regulatory, and accounting relationships and constraints relevant to making economic and financial projections for the industry are individually rather simple. However, the number of these relationships and constraints are so great as to dictate the use of a computer model such as PTm. Moreover, because of interactions between the various industry relationships and constraints, attempts to reduce the number of factors through shortcut approximations are hazardous.[3] Furthermore, such shortcuts, even if based on careful econometric analyses of historical data, would tend to preclude an examination of the implications of structural and policy changes.

---

[3] *To illustrate the point concretely, consider the industry's effective tax rate as it appears in regulatory and shareholder financial reports. This rate is, in fact, a complex function of (among other things): the actual federal, state, and local income tax rates; the industry's plant and equipment expenditures in the current and past years; and, the reduced asset lifetimes, the accelerated methods of depreciation, the investment credits, and the other income statement items allowed for tax purposes, but not for regulatory purposes. These current and past expenditures are themselves a function of: demand growth; the mix of nuclear and non-nuclear capacity built to meet this demand; and the costs per unit of such generating capacity and the related transmission and distribution equipment. Clearly, to assess the industry's future effective tax rate directly is a formidable task; even more clearly, simply to assume the future rate will be the same as the current rate or some average of recent rates is unlikely to be an adequate approximation of the outcome of the detailed calculations or actual events.*

PTm was designed not only to compute rapidly the implications of any given set of assumptions about the future, but also to facilitate the examination of structural and policy changes. Thus, the model is able conveniently to accept input assumptions for over 100 variables, such as the current level of and future changes in: the industry's peak demand; reserve margins; the mix of nuclear and non-nuclear capacity additions; unit costs of generating plants, transmission and distribution capacity, thermal and chemical pollution equipment; etc. PTm then generates projections for a variety of physical and financial variables, including: capacity figures for each of the major segments of the industry; energy losses resulting from thermal water pollution control standards; income statements, balance sheets, funds flows, and reconciliations of regulatory and Internal Revenue Service income tax expense figures; and summary statistics such as interest coverage figures.

FIGURE A-1

INTERACTIONS BETWEEN THE ENVIRONMENT AND THE PHYSICAL AND FINANCIAL CHARACTERISTICS OF THE ELECTRIC UTILITY INDUSTRY

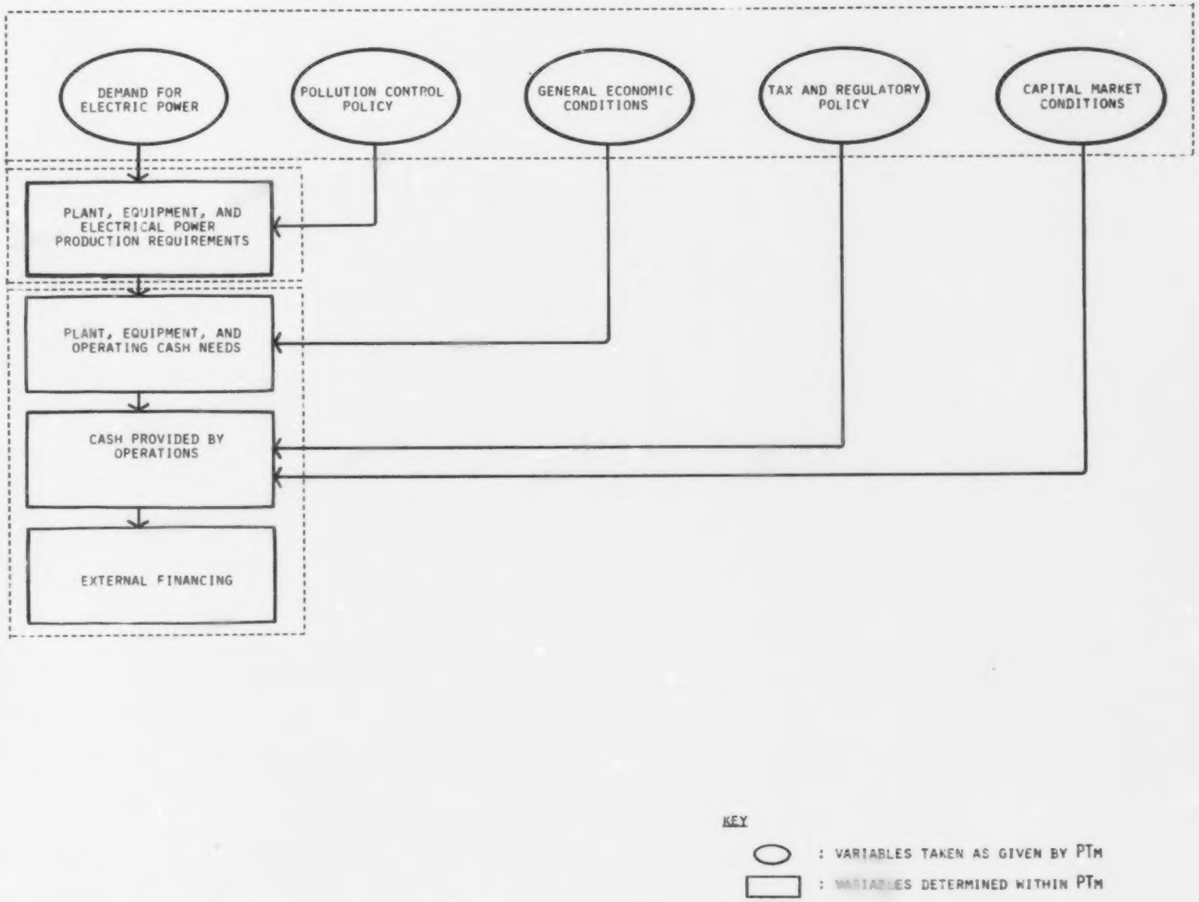
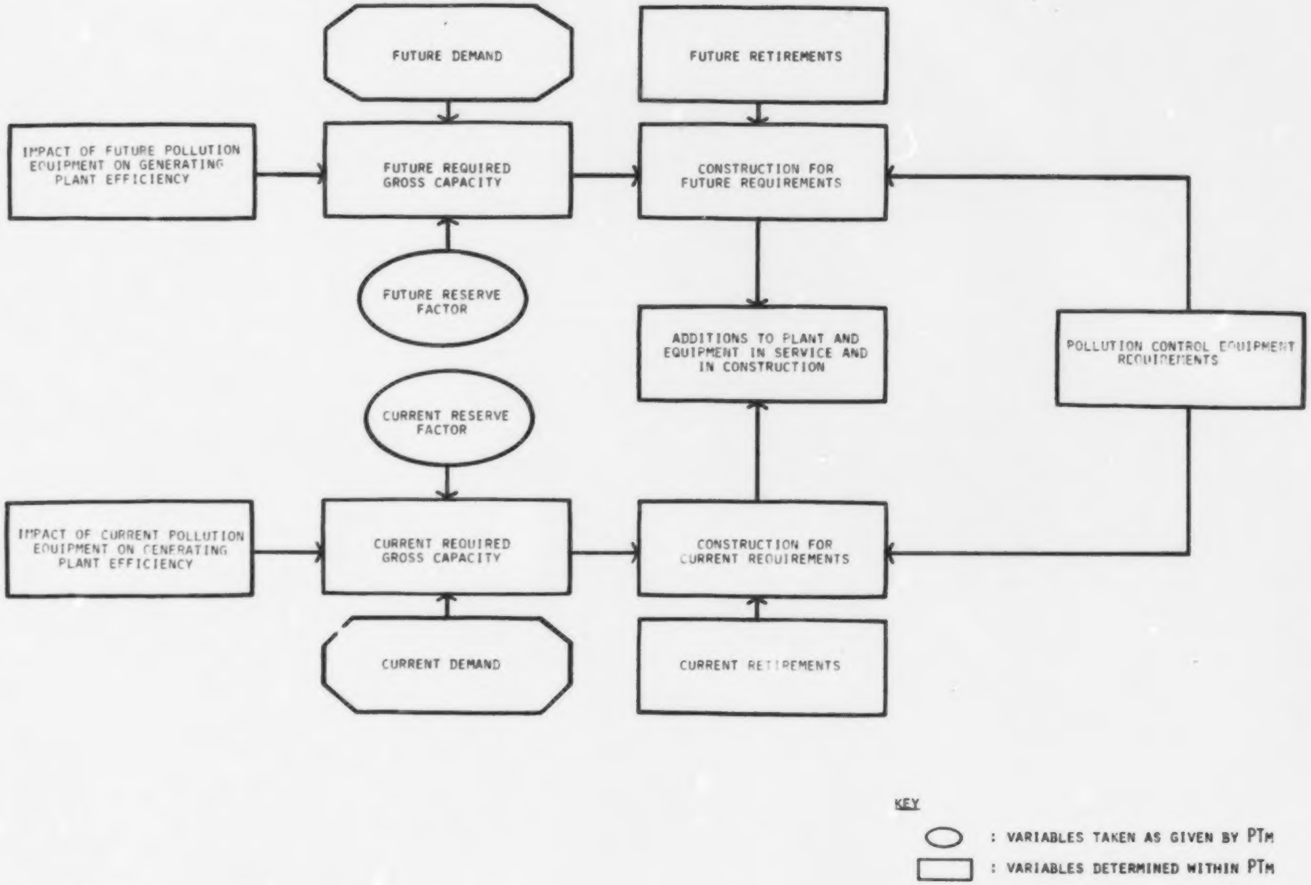

DEMAND FOR ELECTRIC POWER
POLLUTION CONTROL POLICY
GENERAL ECONOMIC CONDITIONS
TAX AND REGULATORY POLICY
CAPITAL MARKET CONDITIONS
PLANT, EQUIPMENT, AND ELECTRICAL POWER PRODUCTION REQUIREMENTS
PLANT, EQUIPMENT, AND OPERATING CASH NEEDS
CASH PROVIDED BY OPERATIONS
EXTERNAL FINANCING
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

FIGURE A-2

DETERMINANTS OF PLANT AND EQUIPMENT IN SERVICE
AND IN CONSTRUCTION FOR THE ELECTRIC UTILITY INDUSTRY


FUTURE DEMAND
FUTURE RETIREMENTS
IMPACT OF FUTURE POLLUTION EQUIPMENT ON GENERATING PLANT EFFICIENCY
FUTURE REQUIRED GROSS CAPACITY
CONSTRUCTION FOR FUTURE REQUIREMENTS
FUTURE RESERVE FACTOR
ADDITIONS TO PLANT AND EQUIPMENT IN SERVICE AND IN CONSTRUCTION
POLLUTION CONTROL EQUIPMENT REQUIREMENTS
CURRENT RESERVE FACTOR
IMPACT OF CURRENT POLLUTION EQUIPMENT ON GENERATING PLANT EFFICIENCY
CURRENT REQUIRED GROSS CAPACITY
CONSTRUCTION FOR CURRENT REQUIREMENTS
CURRENT DEMAND
CURRENT RETIREMENTS
KEY
: VARIABLES TAKEN AS GIVEN BY PTm
: VARIABLES DETERMINED WITHIN PTm

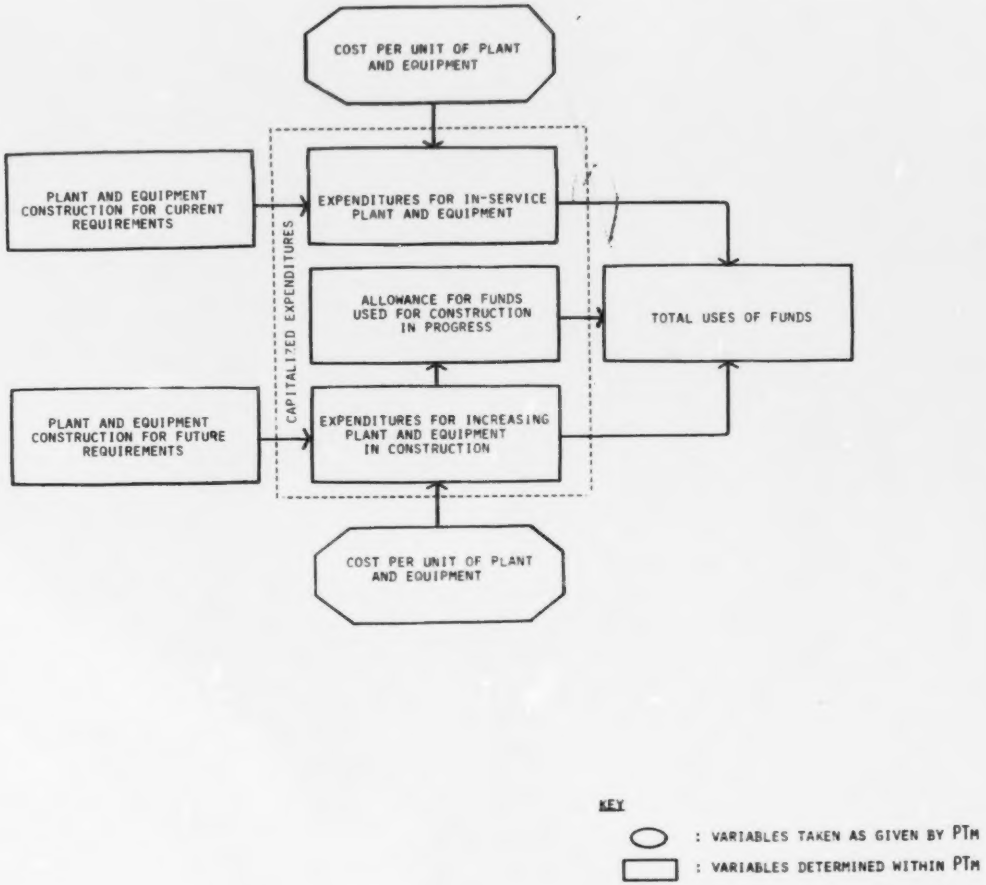


FIGURE A-3

DETERMINANTS OF USES OF FUNDS
FOR THE ELECTRIC UTILITY INDUSTRY

COST PER UNIT OF PLANT AND EQUIPMENT
PLANT AND EQUIPMENT CONSTRUCTION FOR CURRENT REQUIREMENTS
CAPITALIZED EXPENDITURES
EXPENDITURES FOR IN-SERVICE PLANT AND EQUIPMENT
ALLOWANCE FOR FUNDS USED FOR CONSTRUCTION IN PROGRESS
TOTAL USES OF FUNDS
PLANT AND EQUIPMENT CONSTRUCTION FOR FUTURE REQUIREMENTS
EXPENDITURES FOR INCREASING PLANT AND EQUIPMENT IN CONSTRUCTION
COST PER UNIT OF PLANT AND EQUIPMENT
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

FIGURE A-4

DETERMINANTS AND COMPOSITION
OF TOTAL SOURCES OF FUNDS FOR THE ELECTRIC UTILITY INDUSTRY

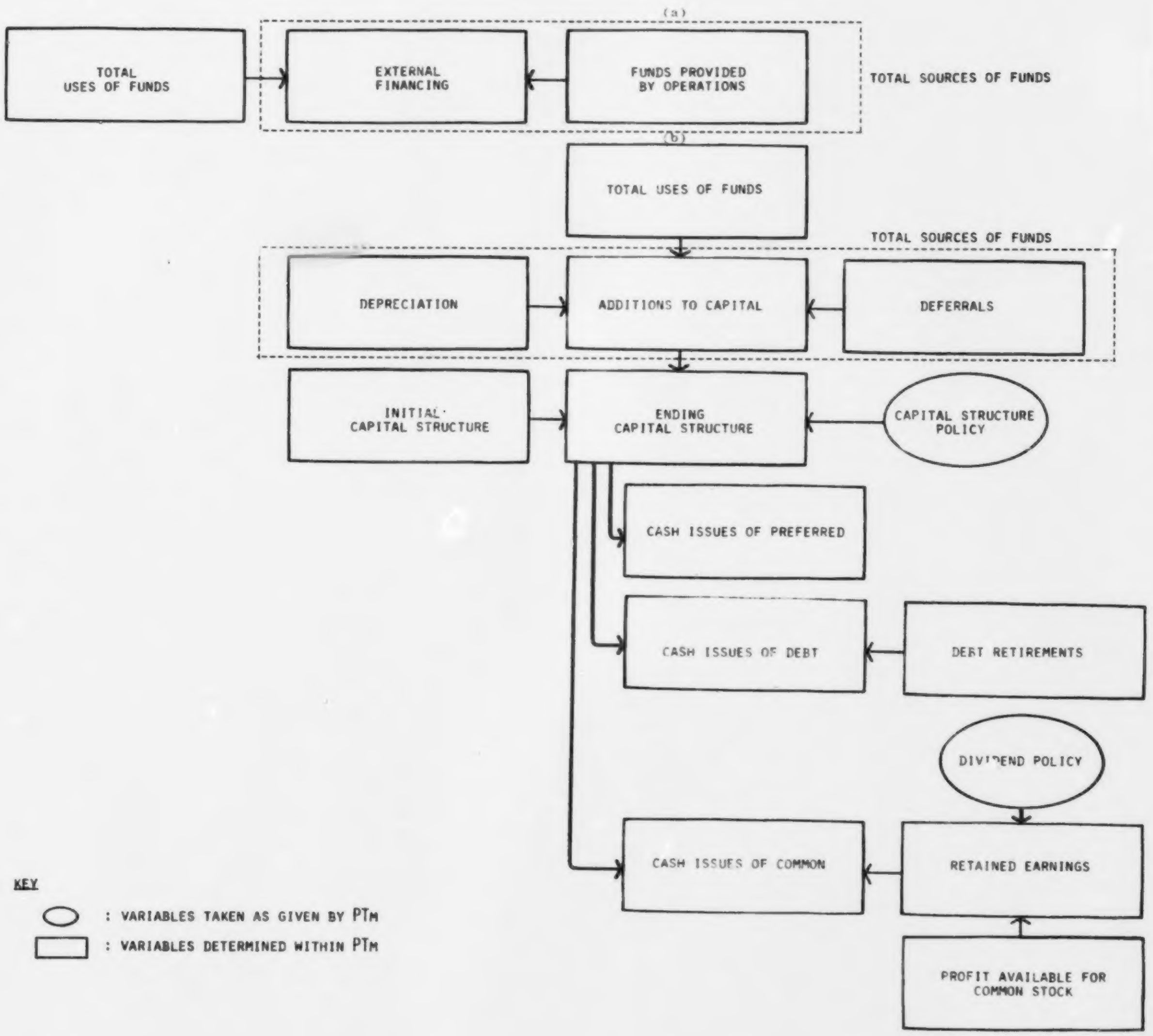
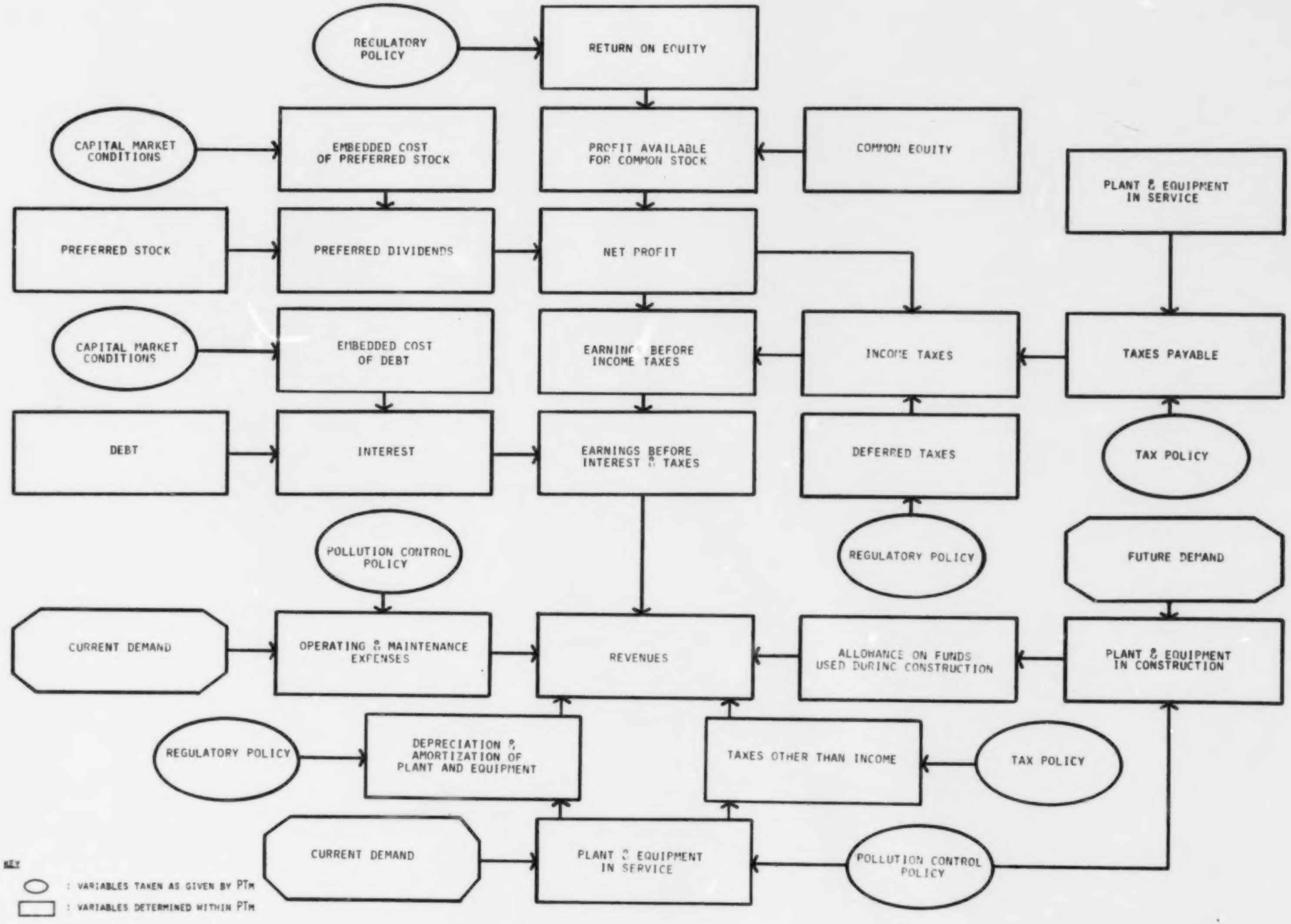

(a)
TOTAL USES OF FUNDS
EXTERNAL FINANCING
FUNDS PROVIDED BY OPERATIONS
TOTAL SOURCES OF FUNDS
(b)
TOTAL USES OF FUNDS
TOTAL SOURCES OF FUNDS
DEPRECIATION
ADDITIONS TO CAPITAL
DEFERRALS
INITIAL CAPITAL STRUCTURE
ENDING CAPITAL STRUCTURE
CAPITAL STRUCTURE POLICY
CASH ISSUES OF PREFERRED
CASH ISSUES OF DEBT
DEBT RETIREMENTS
DIVIDEND POLICY
CASH ISSUES OF COMMON
RETAINED EARNINGS
PROFIT AVAILABLE FOR COMMON STOCK
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

FIGURE A-5

DETERMINANTS OF REVENUES, EXPENSES, AND PROFITS FOR THE ELECTRIC UTILITY INDUSTRY


REGULATORY POLICY
RETURN ON EQUITY
CAPITAL MARKET CONDITIONS
EMBEDDED COST OF PREFERRED STOCK
PROFIT AVAILABLE FOR COMMON STOCK
COMMON EQUITY
PLANT & EQUIPMENT IN SERVICE
PREFERRED STOCK
PREFERRED DIVIDENDS
NET PROFIT
CAPITAL MARKET CONDITIONS
EMBEDDED COST OF DEBT
EARNINGS BEFORE INCOME TAXES
INCOME TAXES
TAXES PAYABLE
DEBT
INTEREST
EARNINGS BEFORE INTEREST & TAXES
DEFERRED TAXES
TAX POLICY
POLLUTION CONTROL POLICY
REGULATORY POLICY
FUTURE DEMAND
CURRENT DEMAND
OPERATING & MAINTENANCE EXPENSES
REVENUES
ALLOWANCE ON FUNDS USED DURING CONSTRUCTION
PLANT & EQUIPMENT IN CONSTRUCTION
REGULATORY POLICY
DEPRECIATION & AMORTIZATION OF PLANT AND EQUIPMENT
TAXES OTHER THAN INCOME
TAX POLICY
CURRENT DEMAND
PLANT & EQUIPMENT IN SERVICE
POLLUTION CONTROL POLICY
KEY
○ : VARIABLES TAKEN AS GIVEN BY PTM
▭ : VARIABLES DETERMINED WITHIN PTM

APPENDIX B: PTm SUMMARY STATISTICS

INTRODUCTION

Throughout the text of this report, TBS has projected the operating conditions within the electric utility industry under differing assumptions with respect to industry growth and, more importantly, pollution control equipment associated with alternatives for both thermal and chemical guidelines. In so doing, an attempt has been made to reduce the output from PTm to a manageable level by focusing on three years (1977, 1983 and 1990), and only three time periods:

short-run (or near-term)	1974-1977
next decade	1974-1983
long-run	1984-1990

The short-run essentially focuses upon the period in which very little can be implemented which will impact the industry's performance with the exception of meeting the 1977 chemical guidelines.

The next decade coincides with the period in which all conversions from open to closed-cycle must be completed as well as the time period specified for compliance with both the 1977 and 1983 chemical guidelines.

KEY VARIABLES

For each set of alternative conditions that was evaluated within this report, the economic and financial projections were summarized for selected years in the form of Exhibit B-1[1]. These data were provided in constant 1974 dollars. In addition, Exhibits B-2 to B-5 provide an example in current dollars of the level of detail within the investor-owned sector which is captured in any given year.

The following detailed explanation of each summary statistic for 1983 baseline conditions should assist in understanding the definitions employed within PTm.

CAPITAL EXPENDITURES

Capital expenditures are the sum of expenditures for plant and equipment placed in service and the change in construction work in progress (CWIP) during any given year. For example, the 1983 for in-service operation in the near future. While these expenditures represent actual cash disbursements by the industry, they are not at this time included in computations of the rate base. Some proportion of the financing costs associated with CWIP is allowed to be capitalized at the time that the plant and equipment are placed in service. In addition, this allowance for funds used during construction is then shown as a noncash source of income for investor-owned utilities. CWIP for 1983 amounted to $67.9 billion (private sector, $56.1; public, $11.8) in current dollars and $43.8 billion in constant 1974 dollars.

---

[1] *Exhibit B-1 reproduces Exhibit 35 from Chapter II.*

EXTERNAL FINANCING

External financing requirements are the sum of long-term debt, preferred stock and common stock issues in any given year, including the refinancing of maturing long-term debt.[2] For example, the 1983 requirement of $27.7 billion in current dollars can be segmented into:

---

[2] *A schedule of long-term debt refundings through 1990 has been estimated from published sources and in no year exceeds $1.7 billion. Further, the TAC-Finance assumed that no new long-term debt issues will mature prior to 1990.*

capital expenditures of $43.9 billion in current dollars can be segmented into:

	Private Sector	Public Sector
Generating Plant: non-nuclear	$ 6.4	$ 1.6
Generating Plant: nuclear	9.4	2.4
Nuclear Fuel	1.2	0.3
Transmission and Distribution	12.9	3.2
Pollution Control Equipment	-	-
Increase in CWIP	5.4	1.1
	$35.3	$ 8.6

This current dollar amount is equivalent to $28.3 billion in constant 1974 dollars.

CONSTRUCTION WORK IN PROGRESS

Construction work in progress (CWIP) represents the cash progress payments which have been made in the form of capital expenditures for plant and equipment currently under construction

	Private Sector	Public Sector
Long-Term Debt Issues	$ 14.3	-
Preferred Stock Issues	2.5	-
Common Stock Issues	5.3	-
	$ 22.1	$ 5.6

These 1983 financing requirements are equivalent to $17.8 billion in constant 1974 dollars.

The difference between capital expenditures and external financing requirements in any given year is the amount of funds generated internally in the form of retained earnings, depreciation and tax deferrals less the refundings of long-term debt. In 1983, internal cash generation in current dollars was:

	Private Sector	Public Sector
Retained Earnings	$ 3.3	-
Depreciation (including nuclear fuel)	8.8	-
Tax Deferrals	1.8	-
	$13.9	$3.0

OPERATING REVENUES

Operating revenues in the investor-owned sector are those required to yield a 14 percent rate of return on average common equity. Public sector revenues are then based on the same revenue per kilowatt-hour. In 1983, total operating revenues were $115.9 billion in current dollars (private sector, $92.7 billion; public sector, $23.2 billion) and $74.7 billion in constant 1974 dollars.

OPERATIONS AND MAINTENANCE EXPENSES

Operations and maintenance expenses include those items so defined by the Federal Power Commission in its *Statistics of Privately-Owned Electric Utilities in the United States*, with the exception of nuclear fuel. For example, the 1983 operations and maintenance expenses are estimated to be $64.5 billion in current dollars (private sector, $47.1; public sector, $17.4) and $38.0 in constant 1974 dollars.

CONSUMER CHARGES

Consumer charges are the average amount per kilowatt-hour which is being paid in any given year. The amount of electrical energy consumed is based upon the growth in peak load demand, the reserve margin and the capacity load factor. For example, the 1977 electrical energy amount of 3160.8 billion kilowatt-hours is obtained from:

- 1973 peak load demand of 351.8 million kilowatts,
- Growth in peak load demand between 1973 and 1983 of approximately 5.5 percent per year,
- Reserve margin of 20 percent,
- Capacity load factory of 49.9 percent, and
- 8760 hours per year.

The average consumer charge per kilowatt-hour is then obtained by dividing operating revenues by the total electrical energy consumed. For example, the average consumer charge for 1983 in constant 1974 dollars is estimated to be:

$$\frac{\$74.7 \text{ billion}}{3160.8 \text{ billion kWh}} = 2.36¢/\text{kWh} = 23.6 \text{ mills/kWh}$$

Exhibit B-1

ECONOMIC AND FINANCIAL PROJECTIONS OF BASELINE CONDITIONS FOR SELECTED YEARS

(dollar figures in billions of 1974 dollars)

	1973	1977	1983	1990
Capital Expenditures				
Total for year	$ 13.9	$ 17.9	$ 28.3	$ 39.1
Total since 1973	--	60.3	203.2	441.4
Construction Work in Progress				
End of year	$ 19.6	$26.5	$ 43.8	$ 62.2
External Financing				
Total for year	$ 7.6	$ 10.9	$ 17.8	$ 23.6
Total since 1973	--	35.8	126.3	272.6
Operating Revenues				
Total for year	$ 39.5	$ 52.5	$ 74.7	$ 104.1
Total since 1973	--	188.8	579.5	1,218.0
Operations & Maintenance Expenses[1]				
Total for year	$ 17.7	$ 26.4	$ 38.0	$ 49.5
Total since 1973	--	92.0	292.5	603.7
Consumer Charges (mills/kWh)				
Average for year	21.4	24.0	23.6	22.4

---

[1] *Excludes nuclear fuel*

Source: PTm

Exhibit B-2

INVESTOR-OWNED ELECTRIC UTILITIES COMBINED INCOME STATEMENT

Baseline Conditions - 1983
(billions of current dollars)

Operating Revenue		$ 92.7
-Operating and Maintenance Expenses (excluding nuclear fuel)	$ 47.1	
-Taxes other than Income	9.7	
-Depreciation (including nuclear fuel)	8.8	
+Allowance for Funds used During Construction (AFDC)	3.6	62.0
Earnings Before Interest and Income Taxes		$ 30.7
-Interest Charges		9.7
Earnings Before Income Taxes		$ 21.0
-Income Taxes (State and Federal)	$ 8.8	
+Investment Tax Credits	0.6	8.2
Net Income		$ 12.8
-Dividends on Preferred Stock	$ 1.7	
-Dividends on Common Stock	7.8	9.5
Retained Earnings		$ 3.3

Source: PTm

Exhibit B-3

INVESTOR-OWNED ELECTRIC UTILITIES COMBINED BALANCE SHEET

Baseline Conditions - 1983
(billions of current dollars)

Asset Accounts		
Gross Plant in Service	$ 264.9	
-Accumulated Depreciation	69.2	
Net Plant in Service		$ 195.7
Net Nuclear Fuel		3.6
Construction Work in Progress		56.1
Net Electric Plant		$ 255.3
Net Working Capital (assumed to be constant)		0.1
Total Assets		$ 255.4
Liability and Equity Accounts		
Deferred Tax Items		$ 15.3
Long-Term Debt--outstanding prior to 1973	$ 37.0	
--issued after 1972	95.4	
Long-Term Debt--Total		$ 132.4
Preferred Stock--outstanding prior to 1973	$ 10.6	
--issued after 1972	13.4	
Preferred Stock--Total		$ 24.0
Owners' Equity--outstanding prior to 1973	$ 31.6	
--cash issues after 1972	29.0	
--retained earnings after 1972	23.4	
Owners' Equity--Total		$ 84.0
Total Liabilities and Owners' Equity		$ 255.4

Source: PTm

Exhibit B-4

INVESTOR-OWNED ELECTRIC UTILITIES COMBINED APPLICATIONS AND SOURCES OF FUNDS

Baseline Conditions - 1983

(billions of current dollars)

Applications of Funds		
Capital Expenditures		
Non-Nuclear Generating Plant	$6.4	
Nuclear Generating Plant	9.4	
Nuclear Fuel	1.2	
Transmission and Distribution Equipment	12.9	
Pollution Control Equipment	0.0	
Increase in Construction Work in Progress	5.4	
Total		$35.3
Refundings of Long-Term Debt		0.8
Total Applications		$36.0
Sources of Funds		
Internal Cash Generation		
Retained Earnings	$3.3	
Depreciation (including nuclear fuel)	8.8	
Deferred Tax Items	1.8	
Total		$13.9
External Financing		
Long-Term Debt	$14.3	
Preferred Stock Issues	2.5	
Common Stock Issues	5.3	
Total		$22.1
Total Sources		$36.0

Source: PTm

Exhibit B-5

INVESTOR-OWNED ELECTRIC UTILITIES COMBINED RECONCILIATION OF TAXES

Baseline Conditions - 1983

(billions of current dollars)

Earnings Before Income Taxes: Reported		$21.0
-Accelerated Depreciation	$ 3.5	
-Allowance for Funds used During Construction (AFDC)	3.6	7.1
Earnings Before Income Taxes: Tax Base		$13.9
Income Taxes: Paid		7.3
-Investment Tax Credits (Actual)	$ 0.4	
+Deferred Tax Items	1.8	
+Investment Tax Credits (Amortized)	0.1	1.5
Income Taxes: Reported		$ 8.8

Source: PTm